2021

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 EXCH
1934 For the fiscal year ended **December 31, 2021**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXC
1934 For the transition period from ______________ to ______________

cop10k2021p1i0.jpg 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
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 [x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section [ ] Yes [x] No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 o Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was 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 req submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such sho 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-accel smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated fil 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 grow company [ ]

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's a effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Ac 7262(b)) by the registered public accounting firm that prepared or issued its audit report. [x]

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 30, 2021, th of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $60. $81.5 billion.

The registrant had 1,299,526,916 shares of common stock outstanding at January 31, 2022.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2022 (Part III)

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Commonly Used Abbreviations

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

Currencies

$ or USD	U.S. dollar
CAD	Canadian dollar
EUR	Euro
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
MBOD	thousand barrels of oil per day
MM	million
MMBOE	million barrels of oil equivalent
MMBOD	million barrels of oil per day
MBOED	thousands of barrels of oil equivalent per day
MMBOED	millions of barrels of oil equivalent per day
MMBTU	million British thermal units
MMCFD	million cubic feet per day

Industry

BLM	Bureau of Land Management
CBM	coalbed methane
E&P	exploration and production
CCUS	carbon capture utilization and storage
FEED	front-end engineering and design
FPS	floating production system
FPSO	floating production, storage and offloading
G&G	geological and geophysical
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 oblig
ASC	accounting standards
ASU	accounting standards
DD&A	depreciation, depletio amortization
FASB	Financial Accounting S Board
FIFO	first-in, first-out
G&A	general and administr
GAAP	generally accepted ac principles
LIFO	last-in, first-out
NPNS	normal purchase norn
PP&E	properties, plants and
VIE	variable interest entit

Miscellaneous

DE&I	diversity, equity and i
EPA	Environmental Protect
ESG	Environmental, Social Governance
EU	European Union
FERC	Federal Energy Regula Commission
GHG	greenhouse gas
HSE	health, safety and env
ICC	International Chambe Commerce
ICSID	World Bank's Internat Centre for Settlement Investment Disputes
IRS	Internal Revenue Serv
OTC	over-the-counter
NYSE	New York Stock Excha
SEC	U.S. Securities and Ex Commission
TSR	total shareholder retu
U.K.	United Kingdom
U.S.	United States of Amer
VROC	variable return of cas

Part I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Busin Properties, contain forward-looking statements including, without limitation, statements relating to ou plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provis Private Securities Litigation Reform Act of 1995. The words *"anticipate," "believe," "budget," "continue," "co "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "objective," "outlook, "potential," "predict," "projection," "seek," "should," "target," "will," "would"* and similar expressions identify forwa statements. The company does not undertake to update, revise or correct any forward-loo unless required to do so under the federal securities laws. Readers are cautioned that such forwa statements should be read in conjunction with the company's disclosures under the headings "Risk Fac on page 20 and "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIO PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 69.

Items 1 and 2. Business and Properties

Corporate Structure

ConocoPhillips is an independent E&P company headquartered in Houston, Texas with oper activities in 14 countries. Our diverse, low cost of supply portfolio includes resource-rich unconvention America; conventional assets in North America, Europe, and Asia; LNG developments; oil s Canada; and an inventory of global conventional and unconventional exploration prospects. On Dec 2021, we employed approximately 9,900 people worldwide and had total assets of about $91 billion. production for the year was 1,567 MBOED.

ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connec anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The mer Conoco and Phillips was consummated on August 30, 2002. In April 2012, ConocoPhillips complete of the downstream business into an independent, publicly traded energy company, Phillips 66.

On January 15, 2021, we completed the acquisition of Concho Resources Inc. (Concho), an exploration and production company with operations in New Mexico and West Texas focuse Permian Basin. For additional information related to this transaction, *see Note 3*.

On December 1, 2021, we completed our acquisition of Shell Enterprises LLC's (Shell) asse Delaware Basin. Assets acquired include approximately 225,000 net acres of producing properties located e For additional information related to this transaction, *see Note 3*.

Segment and Geographic Information

We manage our operations through six operating segments, defined by geographic region: Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. For o segment and geographic information, *see Note 23*.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NG worldwide basis. At December 31, 2021, our operations were producing in the U.S., Norway, Canada, Indonesia, Malaysia, Libya, China and Qatar.

The information listed below appears in the “Supplementary Data - Oil and Gas Operations
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 “Supp
Oil and Gas Operations” disclosures following the Notes to Consolidated Financial Statements. App
percent of our proved reserves are in countries that belong to the Organization for Economic Coope
Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six MCF of
converted to one BOE. See Management’s Discussion and Analysis of Financial Condition and Results of
discussion of factors that will enhance the understanding of the following summary reserve

	Millions of Barrels of Oil Equivaler		
Net Proved Reserves at December 31	**2021**	2020	2
Crude oil			
Consolidated operations	**2,964**	2,051	2,5
Equity affiliates	**63**	68	
Total Crude Oil	**3,027**	2,119	2,(
Natural gas liquids			
Consolidated operations	**644**	340	3
Equity affiliates	**33**	36	
Total Natural Gas Liquids	**677**	376	4
Natural gas			
Consolidated operations	**1,523**	1,011	1,:
Equity affiliates	**617**	621	7
Total Natural Gas	**2,140**	1,632	1,!
Bitumen			
Consolidated operations	**257**	332	2
Total Bitumen	**257**	332	2
Total consolidated operations	**5,388**	3,734	4,4
Total equity affiliates	**713**	725	8
Total company	**6,101**	4,459	5,:

Alaska

The Alaska segment primarily explores for, produces, transports and markets crude oil, na
NGLs. We are the largest crude oil producer in Alaska and have major ownership interests in two of N
largest oil fields located on Alaska's North Slope: Prudhoe Bay and Kuparuk. We also have a 100 p
in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska's large
state, federal and fee exploration leases, with approximately 1.3 million net undeveloped acres a
operations. 2021, Alaska contributed 19 percent of our consolidated liquids production and 1 percent of c
natural gas production.

	Interest	Operator	2021 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	T MB
Average Daily Net Production						
Greater Prudhoe Area	36.1%	Hilcorp	67	16	12	
Greater Kuparuk Area	89.2-94.7	ConocoPhillips	73	-	2	
Western North Slope	100.0	ConocoPhillips	38	-	2	
Total Alaska			178	16	16	1

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well a
Point McIntyre Area fields. Prudhoe Bay, the largest conventional oil field in North America, is th
waterflood and enhanced oil recovery operation, supported by a large gas and water proce
Prudhoe Bay's western satellite fields are Aurora, Borealis, Polaris, Midnight Sun and Orion
McIntyre, Niakuk, Raven, Lisburne and North Prudhoe Bay State fields are part of the Grea
McIntyre Area. Field installations include seven production facilities, two gas plants, two seawater plants a
power station.

In September 2021, rotary drilling commenced after 18 months of no drilling, resulting in f
and brought online. To help offset decline, efforts were focused on increasing rate through well
enhancements, less downtime, and NGL production.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which consists of the Kuparuk Field and four satellit
Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of the Prudhoe Bay Field. Field
include three central production facilities which separate oil, natural gas and water, as well as a se
treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-lateral
bore wells utilizing coiled-tubing drilling.

We operated a coiled-tubing drilling rig in the fourth quarter of 2021, resulting in five opera
and brought online.

Western North Slope

On the Western North Slope, we operate the Colville River Unit, which includes the Alpine F
satellite fields: Nanuq, Fiord and Qannik. The Alpine Field is located 34 miles west of the Kuparuk F
installations include one central production facility which separates oil, natural gas and water.

The Greater Mooses Tooth Unit is the first unit established entirely within the National Petr
Alaska (NPR-A). In 2017, we began construction in the unit with two drill sites: Greater Mooses To
and Greater Mooses Tooth #2 (GMT-2). GMT-1 achieved first oil in 2018 and completed drilling
2021, and the final construction season for GMT-2 was successfully completed, and drilling oper
commenced during the second quarter. First oil for GMT-2 was achieved in the fourth quarter of 2021, a

During 2021, we operated a conventional rotary rig and an extended reach drilling rig in th
resulting in seven operated wells drilled and brought online.

Exploration

Appraisal of the Willow Discovery, located 36 miles from Nuiqsut in the Bear Tooth Unit in t conducted in 2020. There was no appraisal activity in 2021. In August 2021, an Alaska fed vacated the U.S. government's approval granted to our planned Willow project previously approved by October 2020. The Department of Justice did not appeal the decision and neither did we. We are ac supporting the BLM and Department of Interior as they conduct the Supplemental Environmental Impact S process to address issues highlighted by the federal district court. In the interim, we are continuing w in advance of a final investment decision.

The Stony Hill 1 well located to the east of the Greater Mooses Tooth Unit within the NPR-A and abandoned in 2021 and expensed as a dry hole.

A 3D seismic survey covering 234 square miles was completed in 2020 on state and federa currently evaluating this seismic data for future exploration opportunities.

In late 2021, the Coyote Brookian topset exploration prospect in the Kuparuk River Unit wa near vertical sidetrack from an existing wellbore. The well was fracture stimulated and will unde early in 2022 to confirm longer term deliverability.

Transportation

We transport the petroleum liquids produced on the North Slope to Valdez, Alaska through pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.5 percent ownership int and we also have ownership interests in and operate the Alpine, Kuparuk and Oliktok pipelines on

Our wholly owned subsidiary, Polar Tankers, Inc., manages the marine transportation of ou production, using five company-owned, double-hulled tankers, and charters third-party ve tankers 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 48 contiguous U.S. states and Mexico. The segment is organized into the Permian and Gulf Coast and Rockies business units with a po cost of supply, short cycle time, resource-rich unconventional plays, and conventional production f assets. Based on 2021 production volumes, the Lower 48 is the company's largest segment and co percent of our consolidated liquids production and 64 percent of our consolidated natural gas product

In 2021, we completed two acquisitions significantly increasing our Permian position in the January 15, 2021, we completed the acquisition of Concho adding complementary acreage across t Midland basins. On December 1, 2021, we completed the acquisition of Shell's Delaware B adding significant Texas acreage in the Delaware Basin. The accounting close date used for report the Shell transaction was December 31, 2021. For additional information related to these acquisition *see Note 3*

	2021			
	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBC
Average Daily Net Production				
Delaware Basin	162	27	584	2
Midland Basin	89	9	229	1
Permian—Other	11	2	40	
Total Permian	262	38	853	4
Eagle Ford	116	53	251	2
Bakken	59	16	117	
Gulf Coast and Rockies—Other	10	3	119	
Total Gulf Coast and Rockies	185	72	487	3
Total Lower 48	447	110	1,340	7

At December 31, 2021, we held 10.8 million net acres of onshore conventional and unconv in the Lower 48, the majority of which is either held by production or owned by the company. Ou unconventional holdings total approximately 2 million net acres in the following areas:

- 560,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 200,000 net acres in the Eagle Ford, located in South Texas.
- 654,000 net acres in the Permian—Delaware Basin, located in West Texas and south Mexico.
- 266,000 net acres in the Permian—Midland Basin, located in West Texas.
- 293,000 net acres in other areas with unconventional potential.

The majority of our 2021 onshore production activities were centered on continued develop with emphasis on areas with low cost of supply, particularly in growing unconventional plays focus in 2021 included the following areas:

- Delaware Basin—We operated six rigs and two frac crews on average during 2021, operated wells drilled and 95 operated wells brought online. Primarily as a result of acquisition, production increased in 2021 compared with 2020, averaging 286 MBO MBOED, respectively.
- Midland Basin—We operated five rigs and two frac crews on average during 2021, r operated wells drilled and 102 operated wells brought online. Primarily as a result c acquisition, production increased in 2021 compared with 2020, averaging 136 MBO MBOED, respectively.
- Eagle Ford—We operated four rigs and two frac crews on average in the Eagle Ford resulting in 93 operated wells drilled and 160 operated wells brought online. Production incre compared with 2020, averaging 211 MBOED and 186 MBOED, respectively.
- Bakken—We operated one rig and one frac crew for parts of the year in the Bakken operated wells drilled and 21 operated wells brought online. Production increased ir compared with 2020, averaging 94 MBOED and 78 MBOED, respectively.

Dispositions

In the second half of 2021, we completed the sale of certain noncore assets in the Lower 4 2022, we entered into an agreement to sell our interests in additional noncore assets in the Lower 48 transaction is expected to close in the second quarter of 2022. *See Note 3*

Facilities

We operate and own, with varying interests, centralized condensate processing facilities in Mexico in support of our Eagle Ford, Delaware and Midland assets.

Canada

Our Canadian operations consist of the Surmont oil sands development in Alberta and the Montney unconventional play in British Columbia. In 2021, operations in Canada contributed 8 perc consolidated liquids production and 4 percent of our consolidated natural gas production.

	Interest	Operator	2021 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Bitumen MBD	To MBO
Average Daily Net Production							
Surmont	50.0%	ConocoPhillips	-	-	-	69	6
Montney	100.0	ConocoPhillips	8	4	80	-	2
Total Canada			8	4	80	69	9

Surmont

Our bitumen resources in Canada are produced via an enhanced thermal oil recovery meth whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, whic pumped to the surface for further processing. Operations include two central processing fa and treatment and blending of bitumen. At December 31, 2021, we held approximately 600,000 net acre Athabasca Region of northeastern Alberta.

The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, A Surmont is a 50/50 joint venture with TotalEnergies SE that offers long-lived, sustained production. We structurally lowering costs, reducing GHG intensity and optimizing asset performance.

In 2021, we began processing a portion of Surmont's blended bitumen at the Diluent Reco Alberta, unlocking additional value for the asset by providing market access to our heavy c constructed

In 2019, Surmont implemented the use of condensate for bitumen blending through the ce facility 2, enabling the asset to lower blend ratio and diluent supply costs, gain protection from sy supply disruptions and gain optionality on sales products. The alternative blend project was comp at central processing facility 1. Full Surmont Heavy Dilbit (condensate bitumen blend) was pr from both facilities in the fourth quarter of 2021.

Montney

The Montney is an unconventional resource play located in northeastern British Columbia. 31, 2021, we held approximately 300,000 acres of land with 100 percent working interest in the liqui of the Montney.

In 2021, development activity consisted of drilling three horizontal wells and bringing 12 w addition, construction on the second phase of our processing facility started.

Exploration

Our primary exploration focus is assessing our Montney acreage. In 2022, appraisal drilling and completions activity within the Montney will continue to explore the area's resource potential. Additiona exploration acreage in the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands.

Europe, Middle East and North Africa

The Europe, Middle East and North Africa segment consists of operations principally locatec Norwegian Sector of the North Sea; the Norwegian Sea; Qatar; Libya; and terminalling operations in t 2021, operations in Europe, Middle East and North Africa contributed 12 percent of our consolida production and 14 percent of our consolidated natural gas production.

Norway

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production						
Greater Ekofisk Area	30.7-35.1 %	ConocoPhillips	49	2	41	
Heidrun	24.0	Equinor	13	1	35	
Aasta Hansteen	10.0	Equinor	-	-	84	
Alvheim	20.0	Aker BP	9	-	13	
Troll	1.6	Equinor	2	-	58	
Visund	9.1	Equinor	2	1	46	
Other	Various	Equinor	6	-	21	
Total Norway			81	4	298	1

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, i and comprises four producing fields: Ekofisk, Eldfisk, Embla and Tor. The Tor II redevelopment production in December 2020. This project consisted of 8 wells that have all been complet online as of May 2021. Crude oil is exported to Teesside, England, and the natural gas is exporte Germany. The Ekofisk and Eldfisk fields consist of several production platforms and facilities, with dev drilling continuing over the coming years.

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

Aasta Hansteen is a gas and condensate field located in the Norwegian Sea. Produced conc loaded onto shuttle tankers and transported to market. Gas is transported through the Polarled gas pip 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 natural gas from Troll A is transported to Kollsnes, Norway. Crude oil from floating platforms Troll transported to Mongstad, Norway, for storage and export.

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

Visund is an oil and gas field located in the North Sea and consists of a floating drilling, pro processing unit, and subsea installations. Crude oil is transported by pipeline to a nearby third-party field for export via tankers. The natural gas is transported to a gas processing plant at Kollsnes, No the Gassled transportation system.

We also have varying ownership interests in two other producing fields in the Norway secto Sea.

Exploration
In 2021, we prepared for a four well exploration and appraisal campaign to take place in 2 wells include Slagugle appraisal and exploration of the Peder, Bounty and Lamba prospects.

We were awarded two new exploration licenses; PL1122 and PL1123; and two acreage ad and PL1045B.

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

Facilities
We operate and have a 40.25 percent ownership interest in a crude oil stabilization and N facility at Teesside, England to support our Norway operations.

Qatar

	Interest	Operator	2021			
			Crude Oil MBD	NGL MBD	Natural Gas MMCFD	T MB
Average Daily Net Production						
QG3	30.0%	Qatargas Operating Company Limited	13	8	373	

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

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

Libya

	Interest	Operator	**2021**			
			Crude Oil MBD	NGL MBD	Natural Gas MMCFD	T MB
Average Daily Net Production						
Waha Concession	16.3%	Waha Oil Co.	37	-	15	

The Waha Concession consists of multiple concessions and encompasses nearly 13 million the Sirte Basin. In 2021, we had 22 crude liftings from Es Sider, compared with five crude liftings fr 2020, primarily due to the absence of a forced shutdown after a period of civil unrest that cease 2020.

Asia Pacific

The Asia Pacific segment has exploration and production operations in China, Indonesia, M Australia. In 2021, operations in the Asia Pacific segment contributed 6 percent of our consolidated liqu and 17 percent of our consolidated natural gas production.

Australia

	Interest	Operator	2021 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	MB
Average Daily Net Production						
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	-	680	

Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited (37.5 p China Petrochemical Corporation (Sinopec) (25 percent), is focused on producing CBM from the B basins in Queensland, Australia, to supply the domestic gas market and convert the CBM into LNG Origin operates APLNG's upstream production and pipeline system, and we operate the downstrea 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. Approxima wells are ultimately expected to supply both the LNG sales contracts and domestic gas market. The supported by gathering systems, central gas processing and compression stations, water treatment facil export pipeline connecting the gas fields to the LNG facilities. The LNG is being sold to Sinopec ur sales agreements for 7.6 million metric tonnes of LNG per year, and Japan-based Kansai Electric under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

In December 2021, the company announced it has notified Origin Energy that it is exercisi preemption right to purchase an additional 10 percent shareholding interest in APLNG from Origin Energy for $ which will be funded from cash on the balance sheet and subject to customary adjustments. The effe transaction is July 1, 2020 with closing anticipated to occur in the first quarter of 2022 sub Australian government approval. There will be no change to the operational structure of the APLNG jo whereby Origin Energy will remain the upstream operator of the natural gas production and pipeline ConocoPhillips Australia will remain the downstream operator of the LNG facility.

For additional information, see *Note 4* and *Note 10*.

Exploration

In 2019, we entered into an agreement with 3D Oil to acquire a 75 percent interest in and an offshore Exploration Permit (T/49P) located in the Otway Basin, Australia. We obtained an percent interest, increasing our interest to 80 percent, in June 2020. A 3D seismic survey acquisiti completed in October 2021, and this data will be evaluated for future exploration opportunities.

Indonesia

	Interest	Operator	2021 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	M
Average Daily Net Production						
South Sumatra	54%	ConocoPhillips	2	-	294	

During 2021, we operated two PSCs in Indonesia: the Corridor Block located in South Sum Kualakurun in Central Kalimantan. Currently, we have production from the Corridor Block.

Asset Sales
In December 2021, we announced an agreement to sell our subsidiary that indirectly owns 54 percent interest in the Indonesia Corridor Block PSC and a 35 percent shareholding interes Transasia Pipeline Company. The effective date for the transaction is January 1, 2021, with closing p first quarter of 2022.

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

Exploration
We entered into the Central Kalimantan Kualakurun Block PSC in 2015 with an exploration years. We completed the firm working commitment program in 2017, which included satellite mappin kilometer 2D seismic acquisition program. After completion of prospect evaluation, both PSC contrac relinquish rights and return this block to the government. The relinquishment was approve government in August 2021.

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

China

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	T MB
Average Daily Net Production						
Penglai	49.0%	CNOOC	28	-	-	

Penglai
The Penglai 19-3, 19-9 and 25-6 fields are located in the Bohai Bay Block 11/05 and are stages of development. Phase 1 and 2 include production from all three Penglai oil fields.

The Phase 3 Project in the Penglai 19-3 and 19-9 fields consists of three new wellhead pla central processing platform. First production from Phase 3 was achieved in 2018. This project co 186 wells, 126 of which have been completed and brought online as of December 2021.

The Phase 4A Project in the Penglai 25-6 field consists of one new wellhead platform and a production in 2020. This project could include up to 62 new wells, 14 of which have been completed a online as of December 2021.

On April 5, 2021, a fire occurred on the non-operated V platform in the Bohai Bay. On Apr fire was extinguished. We worked with the operator and implemented a recovery plan resulting in p resumption in December 2021.

Exploration
During 2021, exploration activities in the Penglai fields consisted of two successful apprais supporting future developments in the Bohai Bay Block 11/05.

Malaysia

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production						
Gumusut	29.5%	Shell	19	-	-	1
Malikai	35.0	Shell	13	-	-	1
Kebabangan (KBB)	30.0	KPOC	2	-	66	1
Siakap North-Petai	21.0	PTTEP	1	-	-	
Total Malaysia			35	-	66	4

We have varying stages of exploration, development and production activities across appro
acres in Malaysia, with working interests in six PSCs. Four of these PSCs are located in wat
eastern Malaysian state of Sabah: Block G, Block J, the Kebabangan Cluster (KBBC), which we do r
Block SB405, an operated exploration block acquired in 2021. We also operate another two explo
Block WL4-00 and Block SK304, in waters off the eastern Malaysian state of Sarawak.

Block J

Gumusut

We currently have a 29.5 percent working interest in the unitized Gumusut Field. Gumusut
was achieved in 2019. Development drilling associated with Gumusut Phase 3, a four-well prog
to commence in the first quarter of 2022. First oil is anticipated in 2022.

KBBC

The KBBC PSC grants us a 30 percent working interest in the KBB, Kamunsu East and Kam
Upthrown gas and condensate fields. In 2020, we recognized dry hole expense and impaired
carrying value of unproved properties in the Kamunsu East Field that is no longer in our developme

KBB

During 2019, KBB tied-in to a nearby third-party floating LNG vessel which provided increa
capacity. Production from the field has been reduced since January 2020, due to the rupture of a thi
which carries gas production from KBB to one of its markets. The pipeline operator has initiated r
working toward pipeline testing during 2022.

Block G

Malikai

We hold a 35 percent working interest in Malikai. This field achieved first production in Dec
the Malikai Tension Leg Platform, ramping to peak production in 2018. The KMU-1 exploration
and started producing through the Malikai platform in 2018. Malikai Phase 2 development
achieved in February 2021.

Siakap North-Petai

We hold a 21 percent working interest in the unitized Siakap North-Petai (SNP) oil field. Fi
Phase 2 was achieved in November 2021.

Exploration

In 2017, we were awarded operatorship and a 50 percent working interest in Block WL4-0
included the existing Salam-1 oil discovery and encompassed 0.6 million gross acres. In 2018 and 201
two exploration and appraisal wells were drilled, resulting in oil discoveries under evaluation at Salam and
the Patawali wells were expensed as dry holes in 2019. Further exploration and appraisal drilli
2022.

In 2018, we were awarded a 50 percent working interest and operatorship of Block SK304
2.1 million gross acres off the coast of Sarawak, offshore Malaysia. We acquired 3D seismic ov
completed processing of this data in 2019. Exploration drilling is planned for 2022.

In February 2021, we were awarded operatorship and an 85 percent working interest in Bl encompassing 1.4 million gross acres off the coast of Sabah, offshore Malaysia. Acquisition of a 3D seism the acreage is planned for 2022.

Other International

The Other International segment includes activities in Colombia as well as contingencies as prior operations in other countries. As a result of our completed Concho acquisition on January refocused our exploration program and announced our intent to pursue a managed exit from certain

Colombia

We have an 80 percent operated interest in the Middle Magdalena Basin Block VMM-3 exte approximately 67,000 net acres. In addition, we have an 80 percent working interest in th which extends over approximately 58,000 net acres and is contiguous to the VMM-3 Block. The b currently in Force Majeure following a preliminary injunction temporarily suspending hydraulic fracturin

Argentina

On September 16, 2021, ConocoPhillips Petroleum Holdings BV signed and closed the sale ConocoPhillips Argentina Holdings Sarl and ConocoPhillips Argentina Ventures SRL. With th we completed the exit from our Argentina holdings. *See Note 3*

Venezuela

For discussion of our contingencies in Venezuela, *see Note 11*

Other

Marketing Activities

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

Natural Gas

Our natural gas production, along with third-party purchased gas, is primarily marketed in Canada and Europe. Our natural gas is sold to a diverse client portfolio which includes local distribution gas and power utilities; large industrials; independent, integrated or state-owned oil and gas comp marketing companies. To reduce our market exposure and credit risk, we also transport na 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, Europe. These commodities are primarily sold under contracts with prices based on market indices, location, quality and transportation.

LNG

LNG marketing efforts are focused on equity LNG production facilities located in Australia a 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 containment equipment and technology in the deepwater U.S. Gulf of Mexico. MWCC's con system meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subse containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico.

Oil Spill Response Limited (OSRL) - Subsea Well Intervention Service (SWIS)

OSRL-SWIS is a non-profit organization in the U.K. that is an industry funded joint initiativ capability to respond to subsea well-control incidents. Through our SWIS subscription, ConocoPhillips equipment that is maintained and stored in a response ready state. This provides well cap 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 prep program in addition to internal response resources. Many of the OSROs are not-for-profit cooperatives member companies wherein we may actively participate as a member of the board of directors, ste work group or other supporting role. In North America, our primary OSROs include the Marine S Corporation for the continental U.S. and Alaska Clean Seas and Ship Escort/Response Vess the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain members OSROs including Oil Spill Response Limited, the Norwegian Clean Seas Association for Operating C 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 r increase recoveries from our legacy fields, improve the efficiency of our exploration program, produ economically with less emissions and implement sustainability measures.

In early 2021, we established a multi-disciplinary Low Carbon Technologies organization to company's net-zero road map for scope 1 and 2 emissions, understand the new energies landscape, a opportunities for future competitive investment. Throughout 2021, we executed emissions projects across our global portfolio including production efficiency measures and methane and flarin We also completed pre-development work to evaluate large scale wind energy opportunities to pow operations in the Permian, North Sea and Bohai Bay. Within the new energies landscape, the company h opportunities in CCUS and hydrogen. In 2021, CO_2 storage sites were evaluated along the Louisiana Gulf Coast and we initiated activities to provide carbon capture and storage to industrial er early-stage investments in enabling hydrogen technologies and we began evaluating hydrogen op both domestic and international markets.

We are the second-largest LNG liquefaction technology provider globally. Our Optimized Ca LNG® liquefaction technology has been licensed for use in 27 LNG trains around the world, with f ongoing for additional trains.

Delivery Commitments

We sell crude oil and natural gas from our producing operations under a variety of contract
arrangements, some of which specify the delivery of a fixed and determinable quantity. Our commercial o
enters into natural gas sales contracts where the source of the natural gas used to fulfill the contr
spot market or a combination of our reserves and the spot market. Worldwide, we are contract
to deliver approximately 1.3 trillion cubic feet of natural gas and 159 million barrels of crude
contracts have various expiration dates through the year 2030. We expect to fulfill these d
commitments with third-party purchases, as supported by our gas management agreements; proved dev
reserves; and PUDs. See the disclosure on "Proved Undeveloped Reserves" in the "Supplementary Data -
Operations" section following the Notes to Consolidated Financial Statements, for informati
development of PUDs.

Competition

ConocoPhillips is one of the world's leading E&P companies based on both production and r
diversified global asset portfolio. We compete with private, public and state-owned companies in
E&P business. Some of our competitors are larger and have greater resources. Each of our seg
competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned compa
and obtain new sources of supply and to produce oil, bitumen, NGLs and natural gas in an effic
effective manner. We deliver our production into the worldwide commodity markets. Principal meth
competing include geological, geophysical and engineering research and technology; experience and e
economic analysis in connection with portfolio management; and safely operating oil and gas producti

Human Capital Management

Values, Principles and Governance

At ConocoPhillips, our human capital management (HCM) approach is anchored to our core
SPIRIT Values – Safety, People, Integrity, Responsibility, Innovation, and Teamwork – set t
we interact with all of our internal and external stakeholders. In particular, we believe a safe c
successful organization, so we prioritize personal and process safety across the company.
values are a source of pride. Our day-to-day work is guided by the principles of accountability and perf
the way we do our work is as important as the results we deliver. We believe these core va
principles set us apart, align our workforce and provide a foundation for our culture.

Our Executive Leadership Team (ELT) and our Board of Directors play a key role in setting
strategy and driving accountability for meaningful progress. The ELT and Board of Directors engage ofte
related topics. Our HCM programs are overseen and administered by our human resources functio
from business leaders across the company.

We depend on our workforce to successfully execute our company's strategy and we recog
importance of creating a workplace in which our people feel valued. Our HCM programs are built around
we believe are necessary for success: a compelling culture, a world-class workforce and strong
engagement. Each of these pillars is described in more detail below.

A Compelling Culture

How we do our work is what sets us apart and drives our performance. We're experts in w
continuously find ways to do our jobs better. Together, we deliver strong performance, but
We embrace our core cultural attributes that are shared by everyone, everywhere. With two si
acquisitions completed in 2021, we prioritized cultural integration. We seized the opportunity to learn f
each other's cultures. This involved employee engagement, active listening and leveraging data
monitor key workforce and engagement metrics.

Health, Safety and Environment

Our HSE organization sets expectations and provides tools and assurance to our workforce achieve HSE excellence. We manage and assure ConocoPhillips HSE policies, standards and practic ensure business activities are consistently safe, healthy and conducted in an environmentally and responsible manner across the globe. Each business unit manages its local operational risks with parti to process safety, occupational safety and environmental and emergency preparedness risk. targets and deadlines are set and tracked annually to drive strong HSE performance. Progress is tracke to our ELT and the Board of Directors. HSE audits are conducted on business units and staff grou conformance with ConocoPhillips HSE policies, standards and practices where improvement identified and tracked to completion.

We continuously look for ways to operate more safely, efficiently and responsibly. We focus human error by emphasizing interaction among people, equipment and work processes. By being how work is done, recognizing error-likely situations and applying safeguards, we can reduce the like severity of unexpected incidents. We conduct thorough investigations of all serious incidents to unders causes and share lessons learned globally to improve our procedures, training, maintenance progr designs. Through this culture of continuous learning and improvement, we continue to refine our ex processes and tools and enhance our commitment to safe, efficient and responsible operations.

COVID-19 Response

In 2021, our COVID-19 activities were guided by our three company-wide priorities, set at pandemic stages: protect our employees and contractors, mitigate the spread of COVID-19 and safel business. We have pursued these priorities via a coordinated crisis management support team, frequent communications and flexible programs to suit the challenging environment. Our office and adhered to rigorous mitigation protocols implemented across our operations utilizing the most current health authorities. Mitigation measures, including requirements for remote work, vaccines and tes by the specific situations applicable to a region or business function. These measures proved effe lessening the impact to our employees and contractors, mitigating the spread of COVID-19 and minimizi our business disruption.

Diversity, Equity and Inclusion (DEI)

At ConocoPhillips, we value all forms of diversity, provide equitable employee programs an culture of inclusion. Our DEI vision is for our workforce to have a strong sense of belonging and feel their full potential. Our commitment to DEI is foundational to our SPIRIT Values. We hold accountable for having personal DEI goals each year and encourage all global employees to play a part sustaining an inclusive work environment.

The ELT has ultimate accountability for advancing our DEI commitment through a governan that includes an ELT-level DEI Champion, a global DEI Council consisting of senior leaders from organization and company-wide DEI goals. The company sets goals and measures progress based on thr guide our DEI activities: leadership accountability, employee awareness and processes and programs plans and our DEI progress are reviewed regularly with the Board of Directors.

In 2021, HR and the DEI Council reviewed the results of the 2020 Perspectives Pulse DEI e and prioritized action plans tied to employee sentiment. 2021 accomplishments included:

- Refreshing and diversifying the global DEI Council to reflect the diversity we seek a organization;
- Using survey insights to produce six multi-year corporate DEI priorities that will gui 2024;
- Developing a detailed plan for our corporate DEI priorities, made up of 18 specific ta to position us to deliver meaningful progress through 2024; and
- Championing the addition of the 'E' (equity) to D&I; emphasizing the importance of equitable programs that lead to fair outcomes for all employees.

We actively monitor diversity metrics on a global basis. In 2021, we expanded our interna workforce metrics and HCM disclosures, including publishing our 2018-2020 Consolidated EEO-1 Repo inaugural HCM report. Tables of 2021 employee demographics by gender and ethnicity, and by coun below:

2021 Employees by Gender and Race/Ethnicity

	Global		U.S.	
	Male	Female	White	POC
All Employees	74%	26%	72%	28
All Leadership	75	25	79	21
Top Leadership	78	22	85	15
Junior Leadership	75	25	77	23

**"POC" refers to People of Color or racial and ethnic minorities self-reported in the U.S.*

2021 Employees by Country	**Percent of T**
U.S.	61
Norway	18
Canada	8
Indonesia	5
Great Britain	3
Australia	3
China	1
Other Global Locations	1
	100

The Hybrid Office Work Program

In 2021, we introduced the Hybrid Office Work (HOW) program in the U.S., offering a com from both office and home. The HOW program blends the advantages of in-person engagement flexibility for eligible employees where a hybrid schedule is feasible. The design of the U.S adopted in many of our global locations.

A World-Class Workforce

Our HCM approach addresses programs and processes necessary for ensuring we have an the workforce with the skills to meet our business needs. We take a holistic view of HCM that addresses each components of workforce planning. These are described in more detail below.

Recruitment

Our continued success requires a strong global workforce that can contribute the right skil places to achieve our strategic objectives. We offer university internships across multiple disciplines best early-career talent. We partner with top diversity organizations and universities, including organizations and historically black colleges and universities. We also recruit experienced h critical skills with a broad range of expertise and experience. We conduct routine talent assess leaders to ensure we have the organizational capacity and capabilities to execute our business plans. significant steps to embed inclusion into each step of our recruiting practices, including ada we construct job descriptions to using intentionally diverse interview panels.

As necessary, we closely monitor recruitment metrics through our internal university and e dashboards and track voluntary turnover metrics to guide our retention activities.

2021 Hiring & Attrition Metrics	Percent of T
U.S. University hire acceptance	81
U.S. Interns acceptance	76
Diversity hiring - Women	23
Diversity hiring - U.S. POC	35
Total voluntary attrition	5

Employee Engagement and Development

We focus on the engagement and development of our workforce and encourage our emplo
diverse and fulfilling careers with ConocoPhillips. Our workforce is trained through a combination c
formal training, regular feedback and mentoring. Skill-based Talent Management Teams (T
employee development and career progression by skills and location. The TMTs help identify our futu
assess the needs and availability of critical skill-sets within the company. We use a performance man
program focused on objectivity, credibility and transparency. The program includes broad stakehold
real-time recognition and a formal "how" rating to assess behaviors to ensure they align with our SP

We empower our employees to grow their careers through personal and professional devel
opportunities, including individual development plans, a voluntary 360-feedback tool and training on a br
technical and professional skills. Succession planning is a top priority for management and the boar
ensures we have the talent available for future leadership roles to inspire employees to reach their ulti
business limit interruption.

Taking steps to measure and assess employee satisfaction and engagement is at the heart
business success and creating a great place to work for our global workforce. Since 2019, the Conoc
Perspectives Survey has become our primary listening platform for gathering feedback on employee ser
promoting our "Who We Are" culture. Our leadership reviews feedback gathered to guide priorities an
employee feedback strategy is comprised of an annual engagement survey and an annual shorter DE

Compensation, Benefits and Well-Being

We offer competitive, performance-based compensation packages and have global equitab
com Our compensation programs are generally comprised of a base pay rate, the annual Variable C
(VCIP) Program and, for eligible employees, the Restricted Stock Unit (RSU) program. From the CE
frontline worker, every employee participates in VCIP, our annual incentive program, which aligns employee
with ConocoPhillips' success on critical performance metrics and also recognizes individual perfo
RSU program is designed to attract and retain employees, reward performance and align emplo
with stockholders by encouraging stock ownership. Our retirement and savings plans are intenc
employee's financial futures and are competitive within local markets.

We routinely benchmark our global compensation and benefits programs to ensure they ar
inclusive, aligned with company culture and allow our employees to meet their individual n
their families. We provide flexible work schedules and competitive time off, including parer
policies in many locations. In 2021, we enhanced our programs to provide expanded coverage for far
disability support, elder care and childcare. We also provide access to quality childcare, including on
where access locally is a challenge.

Our global wellness programs include biometric screenings and fitness challenges designec
promote a healthy lifestyle. All employees have access to our employee assistance prograi
our locations offer custom programs to support mental well-being.

Compensation Risk Mitigation

We have considered the risks associated with each of its executive and broad-based compe programs and policies. As part of the analysis, we considered the performance measures we use as well a types of compensation, varied performance measurement periods and extended vesting schedules under each incentive compensation program. As a result of this review, management concluded arising from our compensation policies and practices are not reasonably likely to have a material a the company. As part of the Board of Directors' oversight of our risk management programs, t Resources Compensation Committee (HRCC) conducts a similar review with the assistance of its indep compensation consultant. The HRCC agrees with management's conclusion that the risks arising from ou policies and practices are not reasonably likely to have a material adverse effect on the company.

External Engagement

Our employees make our communities stronger. We are proud to support their generous ir local charitable activities through employee giving programs that include United Way campaigns contributions and volunteer grants.

While we have been recognized for our ESG and DEI efforts, we know that it takes ongoing make sustainable progress; therefore, we continue to provide training, build awareness and reinf accountability at all levels of the organization and focus on behaviors and processes that build an environme everyone has the opportunity to succeed.

General

At the end of 2021, we held a total of 1,118 active patents in 50 countries worldwide, inclu U.S. patents. During 2021, we received 40 patents in the U.S. and 45 foreign patents. Our pro processes generated licensing revenues of $65 million related to activity in 2021. The overall profitab segment business is not dependent on any single patent, trademark, license, franchise or concessio

The environmental information contained in Management's Discussion and Analysis of Fina and Results of Operations on pages 58 through 63 under the captions "Environmental" and "Cli incorporated herein by reference. It includes information on expensed and capitalized envi for 2021 and those expected for 2022 and 2023.

Website Access to SEC Reports

Our internet website address is *www.conocophillips.com*. Information contained on our internet webs part of this report on Form 10-K.

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

Item 1A. Risk Factors

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

Risks Related to Our Industry

Our operating results, our ability to execute on our strategy and the carrying valu assets are exposed to the effects of changing commodity prices.

The oil and gas business is a commodity business. Our revenues, operating results and fut growth are highly dependent on the prices we receive for crude oil, bitumen, natural gas and NGLs. Su fluctuate widely depending upon global events or conditions that affect supply and demand, most of control. In early 2020 global oil demand decreased precipitously alongside global COVID-1 shutdowns. Although global oil demand and global oil prices improved through 2021, the global econor remains uncertain. Our industry will continue to be exposed to the effects of changing commodity p volatility in commodity price drivers and the worldwide political and economic environment as well as continued uncertainty caused by armed hostilities in various oil-producing regions around t

Lower crude oil, bitumen, natural gas and NGL prices may have a material adverse effect o operating income, cash flows and liquidity, and may also affect the amount of dividends we pay on our common stock and the amount of shares we elect to acquire as part of the shar program and the timing of such acquisitions. Lower prices may also limit the amount of reserves we economically, thus adversely affecting our proved reserves and reserve replacement ratio a the reduction in our existing reserve levels as we continue production from upstream fields. Pr depressed crude oil prices may affect certain decisions related to our operations, including decisions t investments or curtail operated production.

Significant reductions in crude oil, bitumen, natural gas and NGL prices could also require capital expenditures, impair the carrying value of our assets or discontinue the classification of cer proved reserves. In the past three years, we recognized several impairments, which are described in Note 7 If commo prices decrease relative to their current levels, and as we continue to optimize our investm exercise capital flexibility, it is reasonably likely we could incur future impairments to long-lived ass operations, investments in nonconsolidated entities accounted for under the equity method and unprove Although it is not reasonably practicable to quantify the impact of any future impairments o changes to our unit-of-production rates at this time, our results of operations could be adversely affec

Our business has been, and will continue to be, adversely affected by the coronav (COVID-19) pandemic.

The COVID-19 pandemic and the measures put in place to address it have negatively impa economy, disrupted global supply chains, reduced global demand for oil and gas and created significa disruption of financial and commodity markets. Over the course of the pandemic, public he have recommended or mandated certain precautions to mitigate the spread of COVID-19, includ essential gatherings of people, ceasing all non-essential travel and issuing “social or physic guidelines, “shelter-in-place” orders and mandatory closures or reductions in capacity for non-essentia Although some of these limitations and mandates have been relaxed in certain jurisdictions, others reinstated in areas that have experienced a resurgence of COVID-19 cases and there is no guarantee re not be reimposed in the future. Despite the increased availability of vaccines in certain jurisdictio 19 pandemic may continue or worsen during the upcoming months, including as a result of th infectious variants of the virus, vaccine hesitancy or increased business and social activitie governmental authorities to reinstate restrictions. As a result, the ongoing impact of the C

remains uncertain and will depend on the severity, location and duration of the effects and
disease, the effectiveness and duration of actions taken by authorities to contain the virus or treat i
availability and effectiveness of vaccines or other treatments, and how quickly and to what extent eco
improve.

See our Human Capital Management section within Item 1 and 2—Business and Properties, for additional
information on how we have been impacted and the steps we have taken in response.

Our business is likely to continue to be further negatively impacted by the COVID-19 pand
impacts could include but are not limited to:

- Reduced demand for our products as a result of reductions in travel and commerce, to mandated restrictions or otherwise;
- Disruptions in our supply chain due in part to scrutiny or embargoing of shipments f areas or invocation of force majeure clauses in commercial contracts due to restrictions impo global response to the pandemic;
- Failure of third-parties on which we rely, including our suppliers, contract manufactu contractors, joint venture partners and external business partners, to meet their obligations to t significant disruptions in their ability to do so, which may be caused by their own fi operational difficulties or restrictions imposed in response to the disease outbreak;
- Reduced workforce productivity caused by, but not limited to, illness, travel restricti or government mandates;
- Increased challenges in retention of personnel caused by vaccine hesitancy and the some of our workforce to comply with workplace protocols necessary to ensure the health ar workforce and minimize disruptions to the business, such as vaccine and testing rec the use of personal protective equipment; and
- Voluntary or involuntary curtailments to support oil prices or alleviate storage short products.

Any of these factors, or other cascading effects of the COVID-19 pandemic that are not cur
foreseeable, could materially increase our costs, negatively impact our revenues and damage our financ
results of operations, cash flows and liquidity position. Despite the rollout of vaccines, the pandemic
progressive, and the full extent and duration of any such impacts cannot be predicted at th
of the sweeping impact of the COVID-19 pandemic on daily life around the world and a lack of ce
conditions or when will return to pre-COVID levels.

Unless we successfully develop resources, the scope of our business will decline, adverse impact to our business.

As we produce crude oil and natural gas from our existing portfolio, the amount of our rem
declines. If we are not successful in replacing the crude oil and natural gas we produce wit
prospects for future organic opportunities or through acquisitions, our business will decline. In addition,
successfully develop our reserves is dependent on a number of factors, including our abilit
rights to develop and produce hydrocarbons; our success at reservoir optimization; our ab
long-lead time, capital intensive projects to completion on budget and on schedule; and our ability to
profitably operate mature properties. If we are not successful in developing the resources
our financial condition and results of operations may be adversely affected.

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 com
business. We compete with private, public and state-owned companies in all facets of the exploration an
business, including to locate and obtain new sources of supply and to produce crude oil, bitumen, na
NGLs in an efficient, cost-effective manner. We must compete for the materials, equipment, services,
other personnel (including geologists, geophysicists, engineers and other specialists) necessary t
Some of our competitors are larger and have greater resources than we do, or may have e

term positions or strong governmental or other relationships in countries or areas in which
may be to incur a higher level of risk than we are willing to incur to obtain potential sources
consequence, we may be at a competitive disadvantage in certain respects, such as in acc
materials, equipment, services, resources and personnel. In addition, we may be at a com
disadvantage competing with state-owned companies if they are motivated by political or other fac
business decisions, with less emphasis on financial returns. If we are not successful in our
reserves, our financial condition and results of operations may be adversely affected.

Any material change in the factors and assumptions underlying our estimates of c
and NGL reserves could impair the quantity and value of those reserves.

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

Our business may be adversely affected by price controls, government-imposed li
exports of crude oil, bitumen, natural gas and NGLs, or the unavailability of adequ
compression, transportation, and pipeline facilities and equipment for our produc
oil, bitumen, natural gas and NGLs.

As discussed herein, our operations are subject to extensive governmental regulations. Fro
regulatory agencies have imposed price controls and limitations on production by restrictin
crude oil, bitumen, natural gas and NGL wells below actual production capacity. Similarly,
increased energy costs, circumstances determined to be in the economic interest of the cou
declared emergency, the U.S. government could restrict the export of our products which w
our domestic business. Because legal requirements are frequently changed and subject to
cannot predict whether future restrictions on our business may be enacted or become appl

Our ability to sell and deliver the crude oil, bitumen, natural gas, NGLs and LNG that we pr
the availability, proximity, and capacity of gathering, processing, compression, transportati
and equipment, as well as any necessary diluents to prepare our crude oil, bitumen, natura
transport. Furthermore, we rely on there being sufficient facilities and takeaway capacity t
to reduce routine flaring. The facilities, equipment and diluents we rely on may be tempora
due to market conditions, extreme weather events, regulatory reasons, mechanical reason
conditions, many of which are beyond our control. In addition, in certain newer plays, the
facilities, equipment and diluents may not be sufficient to accommodate production from e
and construction and permitting delays, permitting costs and regulatory or other constraint
the construction, manufacture or other acquisition of new facilities and equipment. If any t
diluents, or any of the transportation methods and channels that we rely on become unava
period, we may incur increased costs to transport our crude oil, bitumen, natural gas, NGLs a
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 w
partners. There is a risk our joint venture participants may at any time have economic, bu
interests or goals that are inconsistent with those of the joint venture or us, or our joint venture par
unable to meet their economic or other obligations and we may be required to fulfill those obligation
by us, or an entity in which we have a joint venture interest, to adequately manage the risks asso
operations, acquisitions or dispositions could have a material adverse effect on the financia
condition or results of operations of our joint ventures and, in turn, our business and operations.

Our operations present hazards and risks that require significant and continuous

The scope and nature of our operations present a variety of significant hazards and risks, i
operational hazards and risks such as explosions, fires, product spills, severe weather, geological even
disputes, geopolitical tensions, armed hostilities, terrorist or piracy attacks, sabotage, civil unrest or
Our operations are subject to the additional hazards of pollution, toxic substances and other en
hazards and risks. Offshore activities may pose incrementally greater risks because of complex sub
conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards cou
of human life, significant property and equipment damage, environmental pollution, impairme
operations, substantial losses to us and damage to our reputation. Our business and operations may b
we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazard
any other major crisis or if we are unable to efficiently restore or replace affected operational compo
capacity. Further, our insurance may not be adequate to compensate us for all resulting losses, and
obtain adequate coverage may increase for us in the future.

Legal and Regulatory Risks

We expect to continue to incur substantial capital expenditures and operating cos
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 e
which are expected to continue to have an increasing impact on our operations. For a description of t
significant environmental laws and regulations, see the “Contingencies—Environmental” and “C
Change” sections of Management’s Discussion and Analysis of Financial Condition and Resu
Operations. These laws and regulations continue to increase in both number and complexity and affect
with respect to, among other things:

- Permits required in connection with exploration, drilling, production and other activi
those issued by national, subnational, and local authorities;
- The discharge of pollutants into the environment;
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury an
emissions, including methane;
- Carbon taxes;
- The handling, use, storage, transportation, disposal and cleanup of hazardous mate
hazardous and nonhazardous wastes;
- The dismantlement, abandonment and restoration of historic properties and faciliti
their useful lives; and
- Exploration and production activities in certain areas, such as offshore environment
oil sands reservoirs and unconventional plays.

We have incurred and will continue to incur substantial capital, operating and maintenance
remediation expenditures as a result of these laws and regulations. In addition, to the extent these exp
assumed by a buyer as a result of a disposition, it may result in our incurring substantial costs if the
to satisfy those obligations. Any failure by us to comply with existing or future laws, regulations and
could result in administrative or civil penalties, criminal fines, other enforcement actions or

against us. To the extent these expenditures, as with all costs, are not ultimately reflected our products and services, our business, financial condition, results of operations and cash flow periods could be materially adversely affected.

Existing and future laws, regulations and internal initiatives relating to global cli such as limitations on GHG emissions may impact or limit our business plans, result in sig 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 i and pending international agreements and national, regional or local legislation and regulatory limit GHG emissions, such as cap and trade regimes, specific emission standards, carbon taxes, restr permitting, increased fuel efficiency standards and incentives or mandates for renewable energy. Altho support many of these legislative and regulatory measures, how and when they are enacted could material adverse effect to our business, financial condition, results of operations and cash flows in f

For example, in November 2021, the U.S. Environmental Protection Agency published a Pro would revise the regulations governing the emission of GHG and volatile organic compounds from production facilities, and emission guidelines for states to use when revising Clean Air Act i plans to limit GHG emissions from existing oil and gas facilities. Although the company supports the regulation of methane from new and existing sources, the final form and substance of any not currently known and could result in additional capital expenditures and compliance, operati maintenance costs, any of which may have an adverse effect on our business and results of operations.

Additionally, in 2021, the U.S. joined the international community at the 26th Conference o (COP26). At the conclusion of COP26, the U.S. and nearly 200 other counties agreed to the Glasgow committing to revisiting and strengthening their current emissions targets to 2030 in 2022 the outstanding elements of the Paris Agreement. In addition, our operations continue in coun which are party to the Paris Agreement. The implementation of current agreements and re well as any future agreements or measures addressing climate change and GHG emissions impact the demand for our products, impose taxes on our products or operations or require us to emissions or reduce emission of GHGs from our operations. As a result, we may experience d commodity prices or incur substantial capital expenditures and compliance, operating, maintenance ar costs, any of which may have an adverse effect on our business and results of operations.

In September 2021, we announced an improvement to our Paris-aligned climate risk frame we committed to an improvement to our targets for reducing our scope 1 and 2 emissions inte gross operated and net equity basis and reaffirmed our commitment to advocate for the reductio emissions through our support for a U.S. carbon price. Compliance with, and achievement of, climate internal initiatives such as the foregoing may increase costs, require us to purchase emissi impact or limit our business plans. If we are not successful in select internal initiatives, we may be affected and potentially need to reduce economic end-of-field life of certain assets and impair associate

Increasing attention to global climate change has also resulted in pressure from and upon financial institutions and/or financial markets to modify their relationships with oil and gas compani investments and/or funding to such companies. For example, Harvard University announce 2021 that it will stop investing its $42 billion endowment in fossil fuels and will let its current inv wind down. As public pressure continues to mount, our access to capital on terms we find fav at all) may be limited and our costs may increase, our reputation could be damaged or our available results of operations may be otherwise adversely affected.

Furthermore, increasing attention to global climate change has resulted in an increased lik governmental investigations and private litigation, which could increase our costs or otherwise adversely business. Beginning in 2017, cities, counties, governments and other entities in several states in the against oil and gas companies, including ConocoPhillips, seeking compensatory damages a

abate alleged climate change impacts. Additional lawsuits with similar allegations are expe
amounts claimed by plaintiffs are unspecified and the legal and factual issues involved in th
unprecedented. ConocoPhillips believes these lawsuits are factually and legally meritless a
vehicle to address the challenges associated with climate change and will vigorously defen
The ultimate outcome and impact to us cannot be predicted with certainty, and we could in
costs associated with defending these and similar lawsuits in the future. We could also rec
alleging a lack of diligence to meet our publicly stated ESG goals, so called "greenwashing"

In addition, although we design and operate our business operations to accommodate expe
conditions, to the extent there are significant changes in the earth's climate, such as more
weather conditions in the markets where we operate or the areas where our assets reside,
increased expenses, our operations and supply chain could be adversely impacted, and der
could fall.

For more information on legislation or precursors for possible regulation relating to global c
affect or could affect our operations and a description of the company's response, *see the "Contingencies–*
Change" section of Management's Discussion and Analysis of Financial Condition and Resul

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

Actions of the U.S., state, local and foreign governments, through sanctions, tax and other
executive and commercial restrictions, could reduce our operating profitability both in the U.S.
locations, restrictions on our operations; leasing restrictions; special taxes or tax assessme
transparency regulations that could require us to disclose competitively sensitive informatio
violate non-disclosure laws of other countries have been imposed or proposed by governm
groups. For example, in 2020 a ballot initiative known as the Fair Share Act was proposed
Alaska, if enacted would have increased the state's share of production revenues and requir
publicly disclose additional financial information. Although ultimately defeated, similar initi
proposed and may be successful in the future. In addition, we may face regulatory change
including, but not limited to, the enactment of tax law changes that adversely affect the fossil fuel in
methane emissions standards, restrictive flaring requirements, and more stringent environmental in
reviews. We also cannot rule out the possibility of similar regulatory shifts and attendant c
implications in other international jurisdictions.

One area subject to significant political and regulatory activity is the use of hydraulic fractu
completion technique that facilitates production of oil and natural gas otherwise trapped in
permeability rock formations. A range of local, state, federal and national laws and regulations currently
some hydraulic fracturing operations, prohibit hydraulic fracturing in some jurisdictions. Althoug
fracturing has been conducted safely for many decades, a number of new laws, regulations and perm
requirements are under consideration which could result in increased costs, operating restrictions, operation
the ability to develop oil and natural gas resources. Certain jurisdictions in which we opera
considering regulations that could impose new or more stringent permitting, disclosure or
requirements on hydraulic fracturing or other oil and natural gas operations, including subs
disposal.
In addition, certain interest groups have also proposed ballot initiatives and constitutional
to restrict oil and natural gas development generally and hydraulic fracturing in particular.
that local, state, or national restrictions or prohibitions are adopted and result in mo
limitations on the production and development of oil and natural gas in areas where we conduct opera
significant costs to comply with such requirements or may experience delays or curtailmen
pursuit of exploration, development or production activities. Such compliance costs and de
limitations, or prohibitions could have a material adverse effect on our business, prospects,
financial condition and liquidity.

The U.S. government can also prevent or restrict us from doing business in foreign countri restrictions and those of foreign governments have in the past limited our ability to operate in, or gain opportunities in various countries. Actions by host governments, such as the expropriation of our oil ass Venezuelan government, have affected operations significantly in the past and may continue to do so i Changes in domestic and international policies and regulations may affect our ability to collect paymen pertaining to the settlement with Petróleos de Venezuela, S.A. (PDVSA) or the ICSID Awar Government of Venezuela; or to obtain or maintain licenses or permits, including those nec drilling and development of wells in various locations. Similarly, the declaration of a "climate emergen in actions to limit exports of our products and other restrictions.

Local political and economic factors in international markets could have a material adverse Approximately 38 percent of our hydrocarbon production was derived from production outs 2021, and 29 percent of our proved reserves, as of December 31, 2021, were located outside the subject to risks associated with operations in both domestic and international markets, including char governmental policies relating to crude oil, natural gas, bitumen, NGLs or LNG pricing and political, economic or diplomatic developments (including the macro effects of international trade po disputes), potentially disruptive geopolitical conditions, and international monetary and currency rate Restrictions on production of oil and gas could increase to the extent governments view su viable approach for pursuing national and global energy and climate policies. In addition, some c we operate lack a fully independent judiciary system. This, coupled with changes in foreign la results in a lack of legal certainty that exposes our operations to increased risks, including increased d enforcing our agreements in those jurisdictions and increased risks of adverse actions by local governme such as expropriations.

Other Risk Factors Facing our Business or Operations

We may need additional capital in the future, and it may not be available on accep at all.

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

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

Our business may be adversely affected by deterioration in the credit quality of, c
with, third-parties with whom we do business.

The operation of our business requires us to engage in transactions with numerous counter
variety of industries, including other companies operating in the oil and gas industry. Thes
default on their obligations to us as a result of operational failures or a lack of liquidity, or f
including bankruptcy. Market speculation about the credit quality of these counterparties, c
continue performing on their existing obligations, may also exacerbate any operational diff
issues they are experiencing, particularly as it relates to other companies in the oil and gas
the volatility in commodity prices. Any default by any of our counterparties may result in c
our obligations under agreements we have made with third-parties or may otherwise adve
or results of operations. In addition, our rights against any of our counterparties as a resu
adequate to compensate us for the resulting harm caused or may not be enforceable at all
circumstances. We may also be forced to incur additional costs as we attempt to enforce any rights we hav
defaulting party, which could further adversely impact our results of operations.

Our ability to execute our capital return program is subject to certain consideratio

In December 2021, we initiated a three-tier capital return program that consists of our ord
share repurchases and a quarterly variable return of cash (VROC).

Ordinary dividends are authorized and determined by our Board of Directors in its sole disc
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 properties;
- The level of distributions paid by comparable companies;
- Our operating expenses; and
- Other factors our Board of Directors deems relevant.

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

- The anticipated level of distributions required to meet our capital returns commitme
- Forward prices;
- Balance sheet cash;
- Total yield; and
- Other factors our Board of Directors deems relevant.

We expect to continue to pay a quarterly ordinary dividend to our stockholders. In additior
current environment, we anticipate also paying a quarterly VROC to our shareholders staggered fro
dividend payment, resulting in up to eight cash distributions to shareholders throughout th
amount of the VROC is variable and will depend upon the above factors, and our Board of D
determine not to pay a VROC in a quarter or may cease declaring a VROC at any time. In addition, ou
Directors may reduce our ordinary dividend or cease declaring dividends at any time, including if it detern
net cash provided by operating activities, after deducting capital expenditures and investments, are
pay desired levels of dividends to our stockholders or to pay dividends to our stockholders

Additionally, as of December 31, 2021, $10.9 billion of repurchase authority remained of th share repurchase program our Board of Directors had authorized. Our share repurchase program obligate us to acquire a specific number of shares during any period, and our decision to commence, disc repurchases in any period will depend on the same factors that our Board of Directors may declaring dividends, among others. In the past we have suspended our share repurchase p response to market downturns, including as a result of the oil market downturn that began in early 202 do so again in the future.

Any downward revision in the amount of our ordinary dividend or VROC or the volume of s purchase under our share repurchase program could have an adverse effect on the market price of c stock.

There are substantial risks with any acquisitions or divestitures we have complet may choose to undertake.

We regularly review our portfolio and pursue growth through acquisitions and seek to dive assets or businesses. We may not be able to complete these transactions on favorable terms, on a t at all. Even if we do complete such transactions, our cash flow from operations may be adversely otherwise the transactions may not result in the benefits anticipated due to various risks, including, b (i) the failure of the acquired assets or businesses to meet or exceed expected returns, including impairment; (ii) the inability to dispose of noncore assets and businesses on satisfactory terms and conditio discovery of unknown and unforeseen liabilities or other issues related to any acquisition fo contractual protections are inadequate or we lack insurance or indemnities, including environmental lia regard to divested assets or businesses, claims by purchasers to whom we have provided contract indemnification.

In addition, we may face difficulties in integrating the operations, technologies, products ar any acquired assets or businesses. For example, we completed two major acquisitions in 2021, acquisition of Concho in January and the acquisition of the Shell Permian assets in Decemb these transactions added approximately 800,000 net acres, thereby significantly increasing our u position and operations in the Permian. We may still encounter difficulties integrating the acquired business. There are a large number of processes, policies, procedures, operations and tech systems that must be integrated in connection with the transactions and the integration of the acqu possible that the integration process could result in the disruption of our ongoing business, in standards, controls, procedures and policies; unexpected integration issues; higher than ex integration costs and an overall post-completion integration process that takes longer than originally anticip been and will be required to devote management attention and resources to integrating the bus and operations. Any delays encountered in the integration process could have an adverse effec our revenues, levels of expenses or capital investment and operating results, which may adversely aff our common stock. In addition, the actual integration may result in additional and unforeseen Although we expect that the strategic benefits, and additional income, as well as the realization of other related to the integration of the acquired assets, may offset incremental transaction-related costs ove able to adequately address integration challenges.

Our technologies, systems and networks may be subject to cyberattacks.

Our business, like others within the oil and gas industry, has become increasingly depende technologies, some of which are managed by third-party service providers on whom we re collect, host or process information. Among other activities, we rely on digital technology to estimate o reserves, process and record financial and operating data, analyze seismic and drilling information a with employees and third-parties. As a result, we face various cybersecurity threats such as att unauthorized access to, or control of, sensitive information about our operations and our e attempts to render our data or systems (or those of third-parties with whom we do business, including cloud and IT service providers) corrupted or unusable, threats to the security of our facilities and infrast as those of third-parties with whom we do business, including third-party cloud and IT service provi attempted cyberterrorism.

In addition, computers control oil and gas production, processing equipment and distributi globally and are necessary to deliver our production to market. A disruption, failure, or a cyberattack o operating systems, or of the networks, software and infrastructure on which they rely, many of which or operated by us, could damage critical production, distribution or storage assets, delay or p to markets, make it difficult or impossible to accurately account for production and settle tran negatively impact public health or safety, economic security, or national security.

Although we have experienced occasional cybersecurity incidents, none have had a materi business, operations or reputation. As cyberattacks have continued to evolve, we have bec new government-imposed security requirements to implement specific mitigation measures to p ransomware attacks and other known threats to information and operations technology. I must continually expend additional resources to continue to modify or enhance our protective m investigate and remediate any vulnerabilities detected. Our implementation of reasonable procedures and controls to monitor and mitigate security threats and to increase security for our infor and infrastructure may result in increased costs. Despite our ongoing investments in security r and business practices, we are unable to assure that any security measures will be completely

If our systems and infrastructure were to be breached, damaged or disrupted, we could be serious negative consequences, including disruption of our operations, damage to our reputation, counterparty trust, reimbursement or other costs, increased compliance costs, litigation exposure and le regulatory fines, penalties or intervention. In addition, we have exposure to cybersecurity incidents a impacts of such incidents related to our data and proprietary information housed on third-party IT s including the cloud. Any of these could materially and adversely affect our business, results of operatior condition, and any of the foregoing can be exacerbated by a delay or failure to detect a cybersecurity full extent of such incident notwithstanding reasonable security procedures and controls. The remote working during the pandemic has introduced additional cybersecurity risk. Although we ha continuity plans in place, our operations may be adversely affected by significant and widespread disr systems and infrastructure that support our business. While we continue to evolve and modify our continuity plans, there can be no assurance that they will be completely effective in avoiding disruptio impacts. Further, our insurance may not be adequate to compensate us for all resulting losses, and obtain adequate coverage may increase for us in the future.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are a defendant in a number of legal and administrative proceedings arising in the ordi business, including those involving governmental authorities under federal, state and local laws regu discharge of materials into the environment. While it is not possible to accurately predict the final outc pending proceedings, if any one or more of such proceedings were to be decided adversely to Cono expect there would be no material effect on our consolidated financial position. See Note 11 for a description of s legal and administrative proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

Information about our Executive Officers

Name	Position Held
William L. Bullock, Jr.	Executive Vice President and Chief Financial Officer
Kontessa S. Haynes-Welsh	Chief Accounting Officer
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer
Timothy A. Leach	Executive Vice President, Lower 48
Andrew D. Lundquist	Senior Vice President, Government Affairs
Dominic E. Macklon	Executive Vice President, Strategy, Sustainability and Technology
Nicholas G. Olds	Executive Vice President, Global Operations
Kelly B. Rose	Senior Vice President, Legal, General Counsel
Heather G. Sirdashney	Vice President, Human Resources and Real Estate and Facilities Se

**On February 17, 2022.*

There are no family relationships among any of the officers named above. Each officer of t elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and appropriate. Each officer of the company holds office from the date of election until the firs directors held after the next Annual Meeting of Stockholders or until a successor is elected next annual meeting is May 10, 2022. Set forth below is information about the executive officer

William L. Bullock, Jr. was appointed Executive Vice President and Chief Financial Officer as of S 2020, having previously served as President, Asia Pacific & Middle East since April 2015. Prior to Vice President, Corporate Planning & Development since May 2012.

Kontessa S. Haynes-Welsh was appointed Chief Accounting Officer in March 2021, having previo Assistant Controller since January 2020. Prior to that, she was Manager, Strategy, Planning Management from June 2018 to December 2019. She became Manager, Finance & Perform September 2016 and served in that role until May 2018. Ms. Haynes-Welsh previously held Director, Lower 48 Strategy & Portfolio Management from February 2016 to September 20

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

Timothy A. Leach was appointed Executive Vice President, Lower 48 in January 2021. Prior to ConocoPhillips, Mr. Leach served as Chairman and Chief Executive Officer of Concho Resou its formation in February 2006, until its acquisition by ConocoPhillips in January 2021.

Andrew D. Lundquist was appointed Senior Vice President, Government Affairs in February 20 he served as managing partner of BlueWater Strategies LLC, since 2002.

Dominic E. Macklon was appointed Executive Vice President, Strategy, Sustainability and Tech 2021, having previously served as Senior Vice President, Strategy, Exploration and Techno September August 2020. Prior to that, he served as President, Lower 48 from June 2018 to August 2020, Vice Presid Planning & Development from January 2017 to June 2018, and President, U.K. from September 201 2017. Mr. Macklon previously served as Senior Vice President, Oil Sands in Canada from July 2012 to 2015.

Nicholas G. Olds was appointed Executive Vice President, Global Operations as of August 202 having previously served as Senior Vice President, Global Operations since August 2020. P he served as Vice President, Corporate Planning & Development from June 2018 to August 2020, Vice P Business Unit, Lower 48 from September 2016 to June 2018, and Vice President, North Slo and Development in Alaska from August 2012 to September 2016.

Kelly B. Rose was appointed Senior Vice President, Legal, General Counsel in September 201 she was a senior partner in the Houston office of an international law firm, Baker Botts L.L.P., w counseled clients on corporate and securities matters. She began her career at the firm in 1991.

Heather G. Sirdashney was appointed Vice President, Human Resources and Real Estate and Fa March 2021, having previously served as Vice President, Human Resources from January 2 that, she served in other leadership roles including Human Resources General Manager, Human Reso Partner Manager, Lower 48, and Director of Human Resources Shared Services.

Part II

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

ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbo

Cash Dividends Per Share

	Dividends	
	2021	2
First	$ **0.430**	0.4
Second	**0.430**	0.4
Third	**0.430**	0.4
Fourth	**0.460**	0.4
Number of Stockholders of Record at January 31, 2022*		38,

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

In December 2021, we announced the addition of a VROC tier to our return of capital prog declaration of ordinary and VROC dividends are subject to the discretion and approval of our Board of Di Board has adopted a dividend declaration policy providing that the declaration of any dividends will be quarterly. For more information on factors considered when determining the level of these distribution, see *"Item 1A—Risk Factors – Our ability to execute our capital return program is subject to certain considerati*

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 D Approximate Value of S that May Y Purchased Und Plans or Prog
October 1-31, 2021	6,100,833	$ 73.36	6,100,833	$ 11,8
November 1-30, 2021	6,367,204	73.42	6,367,204	11,3
December 1-31, 2021	6,751,987	71.65	6,751,987	10,8
	19,220,024	$	19,220,024	

** There were no repurchases of common stock from company employees in connection with the company's broa*
incentive plans

In late 2016, we initiated our current share repurchase program, which has a current total authorization of **$25 billion** of our common stock. As of December 31, 2021, we had repurchased $14.1 Repurchases are made at management's discretion, at prevailing prices, subject to market factors. Except as limited by applicable legal requirements, repurchases may be increased discontinued at any time without prior notice. Shares of stock repurchased under the plan treasury shares. For more information see *"Item 1A—Risk Factors – Our ability to execute our capital ret subject to certain considerations."*

Stock Performance Graph

The following graph shows the cumulative TSR for ConocoPhillips’ common stock in each o
from December 31, 2016 to December 31, 2021. The graph also compares the cumulative total
same five-year period with the S&P 500 Index and our performance peer group consisting of Che
ExxonMobil, Apache, Marathon Oil Corporation, Devon, Occidental, Hess, and EOG weighted according t
peer's stock market capitalization at the beginning of each annual period.

The comparison assumes $100 was invested on December 31, 2016, in ConocoPhillips stoc
index and ConocoPhillips’ peer group and assumes that all dividends were reinvested. The cumu
returns of the peer group companies' common stock do not include the cumulative total return of Co
common stock. The stock price performance included in this graph is not necessarily indicative of fu
performance.

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

Management's Discussion and Analysis is the company's analysis of its financial performan significant trends that may affect future performance. It should be read in conjunction with the financ and notes, and supplemental oil and gas disclosures included elsewhere in this report. It conta looking statements including, without limitation, statements relating to the company's plans, strat objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Securities Litigation Reform Act of 1995. The words "anticipate," "believe," "budget," "continue," "co "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "objective," "outlook, "potential," "predict," "projection," "seek," "should," "target," "will," "would," and similar expressions looking statements. The company does not undertake to update, revise or correct any of the forwa information unless required to do so under the federal securities laws. Readers are cautioned that such looking statements should be read in conjunction with the company's disclosures under the headin "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SE LITIGATION REFORM ACT OF 1995," beginning on page ***69****.*

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

Business Environment and Executive Overview

ConocoPhillips is one of the world's leading E&P companies based on both production and r operations and activities in 14 countries. Our diverse, low cost of supply portfolio includes unconventional plays in North America; conventional assets in North America, Europe and developments; oil sands assets in Canada; and an inventory of global conventional and unc exploration prospects. Headquartered in Houston, Texas, at December 31, 2021, we employed approx people worldwide and had total assets of $91 billion.

Completed Acquisitions

On January 15, 2021, we completed our acquisition of Concho Resources Inc. (Concho), ar oil and gas exploration and production company with operations across New Mexico and West Texas ir transaction for $13.1 billion. *See Note 3*.

In December 2021, we completed our acquisition of Shell Enterprises LLC's (Shell) assets i Basin in an all-cash transaction for $8.7 billion after customary adjustments. Assets acquired incluc 225,000 net acres of producing properties located entirely in Texas. *See Note 3. See Item 1A "Risk Factor further discussion of the risks related to integration of the assets acquired.*

Overview

After an unprecedented 2020, the energy landscape improved throughout 2021 with prices pandemic levels in the second half of the year; however, we expect prices will continue to be cyclical Our view is that a successful business strategy in the E&P industry must be resilient in lower price env also retaining upside during periods of higher prices. As such, we are unhedged, remain highly our investment decisions and continually monitor market fundamentals, including OPEC Plus up supply guidance and inventory levels. Although global oil demand improved through 2021, the glo recovery remains uncertain and subject to various risk factors, including actions taken to stem the p COVID-19.

As the macro energy environment continues to evolve, we are embracing what we believe
required leadership through what we call our triple mandate. We believe that ConocoPhillips will play
in meeting energy transition pathway demand delivering superior and consistent returns on a
through the price cycles, and achieving our net zero ambition on operational emissions, while retain
successfully flexibility to adapt as the future unfolds.

Our triple mandate is supported by financial principles and capital allocation priorities that
to deliver superior returns through the cycles. Our financial principles consist of maintaining
strength providing peer-leading distributions, making disciplined investments, and delivering ESG ex
which are in service to delivering competitive financial returns. Our 2021 acquisitions of Concho
Permian assets further reinforce our differential value proposition.

In 2021, we successfully delivered on our priorities. Total company production was 1,567 M
cash provided by operating activities of $17 billion. We invested $5.3 billion into the business in
capital expenditures and provided returns of capital to shareholders of approximately $6 billion th
ordinary dividend and share repurchases. For 2021, our ordinary dividend returned $2.4 billion whic
increase from 43 cents per share to 46 cents per share, effective in December. Share repurchases r
February and amounted to $3.6 billion inclusive of our paced monetization program related to the Cenov
common shares owned. *See Note 5*. We also demonstrated our commitment to preserving our top
sheet with an announcement to reduce the company's gross debt by $5 billion over five ye
combination of natural and accelerated maturities.

As part of our ongoing portfolio high-grading and optimization efforts, in December 2021, w
two transactions in our Asia Pacific segment enhancing our diverse portfolio. This included noti
Energy of our intent to exercise our preemption right to purchase an additional 10 percent sharehold
APLNG for $1.645 billion, before customary adjustments, and the sale of our interests in Indonesia
approximately $1.4 billion before customary adjustments. In addition to those transactions, in January 2022, w
a divestiture agreement to sell our interest in noncore assets within our Lower 48 segment fo
These transactions are expected to close in the first half of 2022. For more information on APLNG *see Note 4*
more information on pending dispositions, *see Note 3*.

We announced an increase in our disposition target to $4 to $5 billion in proceeds by year-
approximately $2 billion sourced from the Permian Basin. As of year-end 2021, we have ge
billion in disposition proceeds. The proceeds from these transactions will be used in accordance with
priorities, including returns of capital to shareholders and reduction of gross debt.

In December 2021, we announced the initiation of a three-tier return of capital framework.
framework is structured to continue delivering a compelling, growing ordinary dividend and through-cyc
repurchases. It includes the addition of a VROC tier. The VROC tier will provide a flexible tool for meeting
of returning greater than 30 percent of cash from operating activities during periods where co
are meaningfully higher than our planning price range. We have set our expected 2022 total r
from all three tiers at approximately $8 billion. *For more information on our three-tier return of capital fra*
Capital Resources and Liquidity.

In 2021, we reaffirmed and improved upon our commitment to ESG leadership and excelle specific targets we set in October 2020 when we became the first U.S.-based oil and gas company Paris-aligned climate-risk strategy. Our commitment includes:

- Net-zero ambition for operational (scope 1 and 2) emissions by 2050 with active ad carbon price to address end-use (scope 3) emissions;
- Targeting a reduction in gross operated and net equity operational GHG emissions i 50 percent from 2016 levels by 2030;
- Zero routine flaring by 2030, with an ambition to get there by 2025;
- 10 percent reduction target for methane emissions intensity by 2025 from a 2019 b addition to the 65 percent reduction we have made since 2015;
- Adding continuous methane detection devices to our operations, with an initial focu Lower 48 facilities;
- Dedicated low carbon technology organization responsible for identifying and priorit emissions reduction initiatives and opportunities associated with the energy transition, CCUS a
- and ESG performance factoring into executive and employee compensation programs.

To support this commitment, in December 2021, we announced that approximately $0.2 b company-wide capital expenditures would be dedicated to energy transition efforts across global operations aimed at accelerating the reduction of the company's scope 1 and 2 emissions a business opportunities that address end-use emissions and early-stage low-carbon technology oppo leverage the company's adjacencies.

Operationally, we remain focused on safely executing the business. Production increased 4 30 percent in 2021, compared to 2020. Production excluding Libya for 2021 was 1,527 MBOE adjusting for acquisitions and dispositions, impacts from 2020 curtailments, 2021 Winter Storm U Concho two-stream contracted volumes to a three-stream basis, production increased by 2 percent. This increase was primarily due to new production from the Lower 48 and other developme portfolio, partially offset by normal field decline. Production from Libya averaged 40 MBOE

Key Operating and Financial Summary

Significant items during 2021 and recent announcements included the following:

- Announced an increase to expected 2022 return of capital to shareholders to a tota with the incremental $1 billion to be distributed through share repurchases and VROC tiers;
- Acquired and integrated Concho, capturing over $1 billion of synergies and savings schedule; acquired Shell's Permian assets on December 1, 2021;
- Exercised preemption right to purchase an additional 10 percent shareholding intere expected to close in the first quarter of 2022;
- Generated $0.3 billion in disposition proceeds from noncore sales and entered into a sell an additional $1.8 billion in assets, subject to customary closing adjustments;
- Delivered strong operational performance across the company's asset base, resultin production of 1,527 MBOED, excluding Libya;
- Achieved first production from GMT2, Malikai Phase 2, SNP Phase 2; completed Tor started production from a third Montney multi-well pad;
- Net cash provided by operating activities was $17 billion, exceeding capital expendi investments of $5.3 billion;
- Distributed $6.0 billion to shareholders through $2.4 billion in dividends and $3.6 b repurchases, representing over 30 percent return of cash provided by operating act shareholders;
- Ended the year with cash and cash equivalents of $5.0 billion and short-term invest billion, totaling over $5.4 billion in ending cash and cash equivalents and short-term invest
- Initiated a paced monetization of the company's CVE investment, generating $1.1 b proceeds through the sale of 117 million shares, with the funds applied to share repurchases shares remained outstanding at year-end 2021; and
- Advanced the company's net-zero ambition by announcing an increase in scope 1 a emissions intensity-reduction targets to 40 to 50 percent from a 2016 baseline on a net equity operated basis by 2030, from the previous target of 35 to 45 percent on only a gross operate

Business Environment

Brent crude oil prices averaged $71 per barrel in 2021, compared with $42 per barrel in 20 industry has periodically experienced this type of volatility due to fluctuating supply-and-demand co such volatility may persist in the future. Commodity prices are the most significant factor impac and related profitability and reinvestment of operating cash flows into our business. Our strategy is to crea price cycles by delivering on the financial principles that underpin our value proposition; balance peer leading distributions, disciplined investments and ESG excellence, all of which support stro returns.

- **Balance sheet strength.** A strong balance sheet is a strategic asset that provides flexibil cycles. We strive to maintain our 'A'-rating, and we have committed to reducing gro billion over the next five years. This will reduce interest expense and provide resilience in volatility. We ended the year with over $5 billion in cash, maintaining balance sheet strength while completing the all-cash acquisition of Shell's Permian assets.

- **Peer leading distributions.** We believe in delivering value to our shareholders via our thr of capital framework, which consists of a growing, sustainable dividend, share repu beginning in 2022, the addition of VROC. In 2021, we paid dividends on our common stock of $2.4 billion and repurchased $3.6 billion of our common stock partially sourced from our monetization program related to the CVE common shares owned. Our combined dividends and re represented over 30 percent of our net cash provided by operating activities. Our fi $0.20 cents per share was paid on January 14, 2022, to shareholders of record as of Janu Our VROC will be made at the Board of Director's discretion, subject to market conditions and *See Note 5. See "Item 1A—Risk Factors Our ability to execute our capital return program certain considerations."*

- **Disciplined investments.** Our goal is to achieve strong free cash flow by exercising capit
controlling our costs, and safely and reliably delivering production. We expect to m
investments sufficient to sustain production throughout the price cycles. Free cash
funds that are available to return to shareholders, strengthen the balance sheet or reinve
business for future cash flow expansion.

  - **Exercise capital discipline.** We participate in a commodity price-driven and capita
industry, with varying lead times from when an investment decision is made
asset is operational and generates cash flow. As a result, we must invest significant
develop newly discovered fields, maintain existing fields, and construct pipel
facilities. We allocate capital across a geographically diverse, low cost of sup
base, which combined with legacy assets results in low overall production decline.
is the WTI equivalent price that generates a 10 percent after-tax return on a point
fully burdened basis. Fully burdened includes capital infrastructure, foreign excha
carbon, price-related inflation and G&A. In setting our capital plans, we exercise a ri
that evaluates projects using these cost of supply criteria, which we believe
maximization and cash flow expansion using an optimized investment pace,
growth for growth's sake. Our cash allocation priorities call for the investme
capital to sustain production and provide returns of capital to shareholders.

  - **Control our costs.** Controlling operating and overhead costs, without compromi
environmental stewardship, is a high priority. Using various methodologies,
those costs monthly, on an absolute-dollar basis and a per-unit basis and report to
Managing operating and overhead costs is critical to maintaining a competiti
our industry, particularly in a low commodity price environment. The ability to c
operating and overhead costs positively impacts our ability to deliver strong cash from

  - **Optimize our portfolio.** In 2021, we completed the acquisition of Concho and Sh
assets, significantly increasing our unconventional portfolio with many additi
low cost of supply inventory. The addition of this highly complementary acreage
and Delaware basins created a sizeable Permian presence to augment our leadin
unconventional positions in the Eagle Ford and Bakken in the Lower 48. In our Asia Pacific s
notified Origin Energy of our intent to exercise our preemption right to purchase an
percent shareholding interest in APLNG and announced the sale of our interests in

    We continue to evaluate our assets to determine whether they compete for
portfolio and optimize as necessary, directing capital towards the most comp
investments and disposing of assets that don't compete. As such, in conjunction with our
acquisition announcement, we communicated an increase in our planned dis
to $4 to $5 billion in proceeds by year-end 2023 as part of our ongoing portfolio h
optimization efforts.

  - **Add to our proved reserve base.** We primarily add to our proved reserve base in t
    - Acquire interest in existing or new fields.
    - Apply new technologies and processes to improve recovery from exis
    - Successfully explore, develop and exploit new and existing fields.

    As required by current authoritative guidelines, the estimated future date w
reach the end of its economic life is based on historical 12-month first-of-mo
prices and current costs. This date estimates when production will end and affects
estimated reserves. Therefore, as prices and cost levels change from year to
of proved reserves also changes. Generally, our proved reserves decrease a
and increase as prices rise.

Reserve replacement represents the net change in proved reserves, net of p
divided by current year production, as shown in our supplemental reserve table dis
reserve replacement was 377 percent in 2021, reflecting a net increase from
sales as well as higher prices. Our organic reserve replacement, which excluded a
1,115 MMBOE from sales and purchases, was 189 percent in 2021.

In the three years ended December 31, 2021, our reserve replacement was
Our organic reserve replacement during the three years ended December 31, 20
excluded a net increase of 1,022 MMBOE related to sales and purchases, was 88 percen

Access to additional resources may become increasingly difficult as commod
make projects uneconomic or unattractive. In addition, prohibition of direct invest
nations, national fiscal terms, political instability, competition from national c
and lack of access to high-potential areas due to environmental or other regulati
negatively impact our ability to increase our reserve base. As such, the timing and leve
add to our reserve base may, or may not, allow us to fully replace our production o
years.

- **ESG Leadership.** Safety and environmental stewardship, including the operational inte
assets, remain our highest priorities. We are committed to protecting the health and safety
who have a role in our operations and the communities in which we operate. We strive to con
business with respect and care for the local and global environment and systematically mana
sustainable business operations. In September 2021, we reaffirmed and improved
commitment to ESG leadership and excellence and the specific targets that we set in October 20
became the first U.S. based oil and gas company to adopt a Paris-aligned climate-risk strate
comprehensive energy transition strategy is designed to sustainably meet global en
while delivering competitive returns on and of capital through the energy transition. Our
recognizes the importance of reducing society's end-use emissions to meet global cl
E&P company, active only in the upstream side of the business, we do not produce
products directly for consumers. We believe that if everyone addressed their scope 1 and 2 e
3 would also be addressed. This is why we have consistently taken a prominent role i
that scope 3 emissions be addressed through a well-designed economywide price on car
are making early-stage investments in transition opportunities with the potential to
compete that will help address end-use emissions, including CCUS and Hydrogen. W
engaging our supply chain on their emissions targets.

Other significant factors that can affect our profitability include:

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

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Brent crude oil prices averaged $70.73 per barrel in 2021, an increase of 70 percen
$41.68 per barrel in 2020. Similarly, WTI crude oil prices increased 72 percent fron
barrel in 2020 to $67.92 per barrel in 2021. Following COVID-19 economic shutdowns in ear
oil demand increased steadily through the year alongside the global economic recovery
supply restraint, capital discipline by U.S. E&P’s and various unplanned supply disruptions i
countries moderated supply growth, reducing excess global inventories and putting upward p
global oil prices.

Henry Hub natural gas prices increased 85 percent from an average of $2.08 per MI
$3.85 per MMBTU in 2021. Extreme weather events in many parts of the world and sever
liquefaction outages depleted global natural gas inventories in early 2021, generatin
demand for U.S. LNG exports and supporting robust domestic demand.

Our realized bitumen price increased 368 percent from an average of $8.02 per bar
$37.52 per barrel in 2021. The increase was largely driven by strength in WTI, reflective of
global demand and OPEC discipline. The WCS differential to WTI at Hardisty remained fair
high production offsets incremental pipeline capacity. We continue to optimize bitumen p
through improvements in alternate blend capability which results in lower diluent co
to the U.S. Gulf Coast market through rail and pipeline contracts.

Our worldwide annual average realized price increased 70 percent from $32.05 per BOE in 2020 to
per BOE in 2021 primarily due to higher realized oil, natural gas and bitumen prices

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

- **Impairments.** We participate in a capital-intensive industry. At times, our PP&E and i become impaired when, for example, commodity prices decline significantly for long periods estimates are revised downward, a decision to dispose of an asset leads to a write- value, or the current fair value of an investment is less than its carrying amount and the l deemed other than temporary. As we optimize our assets in the future, it is reasonably pos future losses upon sale or impairment charges to long-lived assets used in operatio in nonconsolidated entities accounted for under the equity method, and unproved pro more information on our impairments, see *Note 6* and *Note 7*.

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

- **Fiscal and regulatory environment.** Our operations can be affected by changing economi and political environments in the various countries in which we operate, including c strained relationships with governments that may impact our operations or investments. Th environments could negatively impact our results of operations, and further change government fiscal take could have a negative impact on future operations. Our ma carefully considers the fiscal and regulatory environment when evaluating projects or determ and locations of our activity.

Outlook

Production and Capital

2022 operating plan capital budget is $7.2 billion. The plan includes funding for ongoing d drilling programs, major projects, exploration and appraisal activities, base maintenance and $0.2 projects to reduce the company's scope 1 and 2 emissions intensity and investments in several early- carbon opportunities that address end-use emissions.

Production guidance is 1.8 MMBOED in 2022 including Libya but excluding the impacts fro Indonesia disposition and acquisition of additional APLNG shareholding interest. First quarter 2022 p expected to be 1.75 MMBOED to 1.79 MMBOED.

Operating Segments

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

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

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

Results of Operations

This section of the Form 10-K discusses year-to-year comparisons between 2021 and 2020 ... of-year-to-year comparisons between 2020 and 2019, see "Management's Discussion and Analysis ... Condition and Results of Operations" in Part II, Item 7 of our 2020 10-K.

Consolidated Results

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

Years Ended December 31		Millions of Dollars **2021**	2020	2
Alaska	$	**1,386**	(719)	1,5
Lower 48		**4,932**	(1,122)	4
Canada		**458**	(326)	2
Europe, Middle East and North Africa		**1,167**	448	3,1
Asia Pacific		**453**	962	1,4
Other International		**(107)**	(64)	2
Corporate and Other		**(210)**	(1,880)	
Net income (loss) attributable to ConocoPhillips	$	**8,079**	(2,701)	7,1

Net Income (loss) attributable to ConocoPhillips increased $10.8 billion in 2021. 2021 earn positively impacted by:

- Higher realized commodity prices.
- Higher sales volumes primarily due to our Concho acquisition and absence of produ curtailments. *See Note 3*.
- A gain of $1,040 million after-tax on our Cenovus Energy (CVE) common shares in compared to a $855 million after-tax loss on those shares in 2020.
- Lower exploration expenses due to:
    - Absence of a 2020 impairment for $648 million after-tax for the entire carry capitalized undeveloped leasehold costs related to our Alaska North Slope Ga
    - Lower dry hole expenses.
    - Absence of early cancellation of our 2020 winter exploration program in Alas
    - Absence of unproved property impairment and dry hole expenses in 2020 fo Field in Malaysia, which is no longer in our development plans.
- Higher equity in earnings of affiliates, primarily due to higher LNG sales prices.
- Contingent payments related to prior dispositions in our Canada and Lower 48 segn
- An after-tax gain of $194 million recognized for a FID bonus associated with our Au divestiture in 2020. *See Note 3*.
- Lower impairments, primarily due to the absence of impairments recognized in 202 assets in our Lower 48 segment partially offset by an impairment in our APLNG investment in our Asia Pacific segment. *See Note 7*.

These increases in net income (loss) were partly offset by:

- Higher production and operating expenses and taxes other than income taxes, prim higher sales volumes.
- Higher DD&A expenses caused by higher production volumes, partially offset by low from positive reserve revisions due to higher commodity prices in 2021.
- Absence of a $597 million after-tax gain on our Australia-West divestiture complete
- Restructuring and transaction expenses of $341 million after-tax associated with th Shell acquisitions in addition to mark-to-market impacts on certain key employee compen

- Realized losses on hedges of $233 million after-tax related to derivative positions a our Concho acquisition. These derivative positions were settled entirely within the first *S Note 12*

Income Statement Analysis

Unless otherwise indicated, all results in Income Statement Analysis are before-tax.

Sales and other operating revenues increased 144 percent in 2021, mainly due to higher re commodity prices and higher sales volumes.

Equity in earnings of affiliates increased $400 million in 2021, primarily due to higher earn LNG and crude prices, partially offset by a higher effective tax rate related to equity metho in our Europe, Middle East and North Africa segment.

Gain on dispositions decreased $63 million in 2021, primarily due to the absence of a $587 related to our 2020 Australia-West divestiture and a $179 million loss associated with the sale of non in our Other International segment. The decreases were partially offset by a $200 million related to a FID associated with our Australia-West divestiture, gains recognized for contingent payments associated with p dispositions in our Canada and Lower 48 segments and gains on sales of certain noncore assets in our Lo

Other income (loss) increased $1.7 billion in 2021, primarily due to a gain of $1,040 millio common shares in 2021, as compared to a $855 million loss on those shares in 2020. *See Note 5*

Purchased commodities increased 125 percent in 2021, primarily in line with higher gas an and volumes.

Production and operating expenses increased $1,350 million in 2021, primarily in line with production volumes.

Selling, general and administrative expenses increased $289 million in 2021, primarily due and restructuring expenses associated with our Concho acquisition and higher compensation an costs, including mark-to-market impacts of certain key employee compensation programs.

Exploration expenses decreased $1,113 million in 2021, primarily due to the absence of 20 including an $828 million impairment for the entire carrying value of capitalized undeveloped leaseh to our Alaska North Slope Gas asset, the early cancellation of our 2020 winter exploration progra of unproved property impairment and dry hole expenses from 2020 for the Kamunsu East Malaysia. Also lower 2021 dry hole expenses in Alaska.

Impairments decreased $139 million in 2021, primarily due to the absence of impairments 2020 for assets in our Lower 48 segment partially offset by an impairment in our APLNG in included within our Asia Pacific segment in 2021. For additional information, *see Note 7* and *Note 13*.

Taxes other than income taxes increased $880 million in 2021, caused primarily by higher prices and higher Lower 48 sales volumes.

Foreign currency transaction (gains) losses decreased $50 million in 2021 due to the abser gains other remeasurements.

See *Note 17—Income Taxes* for information regarding our income tax provision and effective tax

Summary Operating Statistics

		2021	2020	2
Average Net Production				
Crude oil (MBD)				
Consolidated Operations		**816**	555	6
Equity affiliates		**13**	13	
Total crude oil		**829**	568	7
Natural gas liquids (MBD)				
Consolidated Operations		**134**	97	1
Equity affiliates		**8**	8	
Total natural gas liquids		**142**	105	1
Bitumen (MBD)		**69**	55	
Natural gas (MMCFD)				
Consolidated Operations		**2,109**	1,339	1,7
Equity affiliates		**1,053**	1,055	1,0
Total natural gas		**3,162**	2,394	2,8
Total Production (MBOED)		**1,567**	1,127	1,3
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per bbl)				
Consolidated Operations	$	**67.61**	39.56	60
Equity affiliates		**69.45**	39.02	61
Total crude oil		**67.64**	39.54	60
Natural gas liquids (per bbl)				
Consolidated Operations		**31.04**	12.90	18
Equity affiliates		**54.16**	32.69	36
Total natural gas liquids		**32.45**	14.61	20
Bitumen (per bbl)		**37.52**	8.02	31
Natural gas (per mcf)				
Consolidated Operations		**6.00**	3.17	4
Equity affiliates		**5.31**	3.71	6
Total natural gas		**5.77**	3.41	5
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical, lease rental, and other	$	**300**	374	3
Leasehold impairment		**10**	868	2
Dry holes		**34**	215	2
Total Exploration Expenses	$	**344**	1,457	7

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NG worldwide basis. At December 31, 2021, our operations were producing in the U.S., Norway, Canada, Indonesia, China, Malaysia, Qatar and Libya.

Total production, including Libya, of 1,567 MBOED increased 440 MBOED or 39 percent in with 2020, primarily due to:

- Higher volumes in Lower 48 due to our Concho acquisition.
- New wells online in Lower 48, Canada, Norway, Malaysia and Alaska.
- Absence of production curtailments, primarily in our North American assets.
- Higher production in Libya due to the absence of a forced shutdown of the Es Sider and other eastern export terminals.
- Improved well performance in Norway, Canada, Alaska and China.

The increase in production during 2021 was partly offset by:

- Normal field decline.
- Absence of production from Australia-West due to our second quarter 2020 disposit

Production excluding Libya for 2021 was 1,527 MBOED. After adjusting for closed acquisiti dispositions, impacts from 2020 curtailments, 2021 Winter Storm Uri and the conversion of Concho two contracted volumes to a three-stream basis, production increased by 28 MBOED or 2 percent. This inc primarily due to new production from the Lower 48 and other development programs across the portfolio by normal field decline. Production from Libya averaged 40 MBOED in 2021.

Alaska

		2021	2020	2
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**1,386**	(719)	1,5
Average Net Production				
Crude oil (MBD)		**178**	181	2
Natural gas liquids (MBD)		**16**	16	
Natural gas (MMCFD)		**16**	10	
Total Production (MBOED)		**197**	198	2
Average Sales Prices				
Crude oil ($ per bbl)	$	**69.87**	42.12	64
Natural gas ($ per mcf)		**2.81**	2.91	3

The Alaska segment primarily explores for, produces, transports and markets crude oil, NG gas. In 2021, Alaska contributed 19 percent of our consolidated liquids production and less than 1 consolidated natural gas production.

Net Income (Loss) Attributable to ConocoPhillips

Alaska reported earnings of $1,386 million in 2021, compared with a loss of $719 million i

Earnings were positively impacted by:

- Higher realized crude oil prices.
- Absence of 2020 exploration expenses, including a $648 million after-tax impairmer with the carrying value of our Alaska North Slope Gas assets and the early cancellation of ou exploration program. *See Note 6*.
- Lower dry hole expenses.

Earnings were negatively impacted by:

- Higher taxes other than income taxes primarily due to higher realized crude oil pric

Production

Average production decreased 1 MBOED in 2021 compared with 2020, primarily due to:

- Normal field decline.

The production decrease was partly offset by:

- Absence of curtailments.
- Improved production at our Western North Slope assets as a result of net royalty i associated with periodic redetermination.
- Improved performance in the Greater Prudhoe Area and Western North Slope asse
- New wells online across the segment.

Lower 48

		2021	2020	2
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**4,932**	(1,122)	4
Average Net Production				
Crude oil (MBD)		**447**	213	2
Natural gas liquids (MBD)*		**110**	74	
Natural gas (MMCFD)*		**1,340**	585	6
Total Production (MBOED)		**780**	385	4
Average Sales Prices				
Crude oil ($ per bbl)**	$	**66.12**	35.17	55
Natural gas liquids ($ per bbl)		**30.63**	12.13	16
Natural gas ($ per mcf)**		**4.38**	1.65	2

**Includes conversion of previously acquired Concho two-stream contracts to three-stream initiated in the fourth*
***Average sales prices, including the impact of hedges settling per initial contract terms in the first quarter of 2*
Concho acquisition were $65.19 per barrel for crude oil and $4.33 per mcf for natural gas for the year ended December 3
March 31, 2021, we had settled all oil and gas hedging positions acquired from Concho. See Note 12.

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf o
2021, Lower 48 contributed 55 percent of our consolidated liquids production and 64 percent
consolidated natural gas production.

Net Income (Loss) Attributable to ConocoPhillips

Lower 48 reported earnings of $4,932 million in 2021, compared with a loss of $1,122 mill
Earnings were positively impacted by:

- Higher realized crude oil, NGL and natural gas prices.
- Higher sales volumes due to our Concho acquisition and the absence of production
- Lower impairments, primarily related to developed properties in our noncore assets written down to fair value due to lower commodity prices and development plan changes. See Note 7 and Note 13.
- Higher gains on dispositions related to selling our interests in certain noncore assets. See Note 3

Earnings were negatively impacted by:

- Higher DD&A expenses, production and operating expenses and taxes other than in primarily due to higher production volumes. Partially offsetting the increase in DD&A expens rates from price-related reserve revisions.
- Impacts resulting from our Concho acquisition, including higher selling, general and expenses for transaction and restructuring charges, as well as realized losses on de settlements. See Note 3 and Note 12.

Production

Total average production increased 395 MBOED in 2021 compared with 2020, primarily due

- Higher volumes due to our Concho acquisition.
- New wells online from our development programs in Permian, Eagle Ford and Bakk
- Absence of curtailments.

These production increases were partly offset by:

- Normal field decline.

Canada

		2021*	2020*	201
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**458**	(326)	2
Average Net Production				
Crude oil (MBD)		**8**	6	
Natural gas liquids (MBD)		**4**	2	
Bitumen (MBD)		**69**	55	
Natural gas (MMCFD)		**80**	40	
Total Production (MBOED)		**94**	70	
Average Sales Prices				
Crude oil ($ per bbl)	$	**56.38**	23.57	40
Natural gas liquids ($ per bbl)		**31.18**	5.41	19
Bitumen ($ per bbl)		**37.52**	8.02	31
Natural gas ($ per mcf)		**2.54**	1.21	0

**Average sales prices include unutilized transportation costs.*
***Average prices for sales of bitumen produced excludes additional value realized from the purchase and sale o 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 Montney unconventional play in British Columbia. In 2021, Canada contributed 8 percent of our con production and 4 percent of our consolidated natural gas production.

Net Income (Loss) Attributable to ConocoPhillips

Canada operations reported earnings of $458 million in 2021 compared with a loss of $326
Earnings were positively impacted by:

- Higher realized bitumen prices and crude oil prices.
- After-tax gains on disposition related to contingent payments of $246 million in 202 with the sale of certain assets to CVE in 2017.
- Higher sales volumes in our Surmont and Montney assets.

Earnings were negatively impacted by:

- Higher production and operating expenses primarily due to increased Surmont and production.

Production

Total average production increased 24 MBOED in 2021 compared with 2020. The productio primarily due to:

- Improved well performance in Surmont.
- New wells online in Montney.
- Production from our Kelt acquisition completed in the third quarter of 2020.
- Absence of curtailments.

Europe, Middle East and North Africa

		2021	2020	2
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**1,167**	448	3,
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**118**	86	1
Natural gas liquids (MBD)		**4**	4	
Natural gas (MMCFD)		**313**	275	4
Total Production (MBOED)		**175**	136	2
Average Sales Prices				
Crude oil ($ per bbl)	$	**68.97**	43.30	64
Natural gas liquids ($ per bbl)		**43.97**	23.27	29
Natural gas ($ per mcf)		**13.27**	3.23	4

The Europe, Middle East and North Africa segment consists of operations principally locate
Norwegian sector of the North Sea; the Norwegian Sea; Qatar; Libya; and terminalling operations in t
2021, our Europe, Middle East and North Africa operations contributed 12 percent of our consolidated
production and 14 percent of our consolidated natural gas production.

Net Income Attributable to ConocoPhillips

The Europe, Middle East and North Africa segment reported earnings of $1,167 million in 2
with earnings of $448 million in 2020. Earnings were positively impacted by:

- Higher realized natural gas, crude oil and NGL prices.
- Higher LNG sales prices, reflected in equity in earnings of affiliates.
- Higher sales volumes of crude oil and LNG.

Earnings were negatively impacted by:

- Higher taxes.
- Higher DD&A expenses and production and operating expenses. Partly offsetting th
  DD&A expenses were lower rates from positive reserve revisions.

Consolidated Production

Average consolidated production increased 39 MBOED in 2021, compared with 2020. The
production increase was primarily due to:

- Higher production in Libya due to the absence of a forced shutdown of the Es Sider
  and other eastern export terminals.
- Improved well performance in Norway.
- New production from Norway drilling activities, including our Tor II redevelopment
  achieved full production in 2021.

These production increases were partly offset by:

- Normal field decline.

Asia Pacific

		2021	2020	2
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**453**	962	1,4
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**65**	69	
Natural gas liquids (MBD)		**-**	1	
Natural gas (MMCFD)		**360**	429	6
Total Production (MBOED)		**125**	141	1
Average Sales Prices				
Crude oil ($ per bbl)	$	**70.36**	42.84	65
Natural gas liquids ($ per bbl)		**-**	33.21	37
Natural gas ($ per mcf)		**6.56**	5.39	5

The Asia Pacific segment has operations in China, Indonesia, Malaysia and Australia. Durin Pacific contributed 6 percent of our consolidated liquids production and 17 percent of our consolid production.

Net Income Attributable to ConocoPhillips

Asia Pacific reported earnings of $453 million in 2021, compared with $962 million in 2020 in earnings was mainly due to:

- An impairment of $688 million after-tax on our APLNG investment. See *Note 4* and *Note 13*.
- Absence of a $597 million after-tax gain related to our Australia-West divestiture. See *Note 3*.
- Absence of sales volumes associated with Australia-West.

Earnings were positively impacted by:

- Higher crude oil and natural gas prices.
- Higher LNG sales prices, reflected in equity in earnings of affiliates.
- An after-tax gain of $194 million recognized for a FID bonus associated with our Au divestiture. For additional information related to this FID bonus, see *Note 3* and *Note 11*.

Consolidated Production

Average consolidated production decreased 16 MBOED in 2021, compared with 2020. The primarily due to:

- The divestiture of our Australia-West assets that contributed 18 MBOED in 2020.
- Normal field decline.

These production decreases were partly offset by:

- Development activity at Bohai Bay in China.
- First production in Malikai Phase 2 and SNP Phase 2.
- The absence of curtailments across the segment and increased demand in Indonesi supply restrictions.

Other International

		2021	2020	20
Net Income (Loss) Attributable to ConocoPhillips ($MM)	**$**	**(107)**	(64)	26

The Other International segment includes exploration and appraisal activities in Colombia a contingencies associated with prior operations in other countries. As a result of our Concho acquisition, w exploration program and announced our intent to pursue managed exits from certain areas

Other International operations reported a loss of $107 million in 2021, compared with a los in 2020. Earnings were negatively impacted by:

- A $137 million after-tax loss on divestiture related to our Argentina exploration inte See Note
- Absence of a $29 million after-tax benefit to earnings from the dismissal of arbitrati prior operations in Senegal recognized in the first quarter of 2020.

Changes to earnings were positively impacted by:

- Absence of exploration expenses associated with dry hole costs and a full impairme undeveloped leasehold costs in Colombia in the fourth quarter of 2020.

Corporate and Other

		Millions of Dollars		
		2021	2020	2
Net Income (Loss) Attributable to ConocoPhillips				
Net interest	**$**	**(801)**	(662)	(6
Corporate general and administrative expenses		**(317)**	(200)	(2
Technology		**25**	(26)	1
Other		**883**	(992)	7
	$	**(210)**	(1,880)	

Net interest consists of interest and financing expense, net of interest income and capitaliz interest expense increased $139 million in 2021 compared with 2020, primarily due to high balances assumed due to our Concho acquisition. *See Note 9*.

Corporate G&A expenses include compensation programs and staff costs. These expenses $117 million in 2021 compared with 2020, primarily due to restructuring expenses associated wi acquisition and mark to market adjustments associated with certain compensation progran *See Note 16*

Technology includes our investment in new technologies or businesses, as well as licensing Activities are focused on both conventional and tight oil reservoirs, shale gas, heavy oil, oil sands, enhar as well as LNG. Earnings from Technology increased by $51 million in 2021 compared with 2020, p higher licensing revenues.

The category "Other" includes certain foreign currency transaction gains and losses, enviro associated with sites no longer in operation, other costs not directly associated with an ope premiums incurred on the early retirement of debt, holding gains or losses on equity secur pension settlement expense. Earnings in "Other" increased by $1,875 million in 2021 compared wi primarily due to a gain of $1,040 million on our CVE common shares in 2021, compared with a $855 mil 2020.

Capital Resources and Liquidity

Financial Indicators

	Millions of Dollars Except as Indicated		
	2021	2020	
Net cash provided by operating activities	$ **16,996**	4,802	11
Cash and cash equivalents	**5,028**	2,991	5
Short-term investments	**446**	3,609	3
Short-term debt	**1,200**	619	
Total debt	**19,934**	15,369	14
Total equity	**45,406**	29,849	35
Percent of total debt to capital*	**31%**	34	
Percent of floating-rate debt to total debt	**4%**	7	

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding so
cash generated from operating activities, proceeds from asset sales, our commercial paper and
program and our ability to sell securities using our shelf registration statement. In 2021, the primar
available cash were $8.7 billion for the acquisition of Shell Permian; $5.3 billion to support our ongo
expenditures and investments program; $3.6 billion to repurchase our common stock; $2.4 billion to pa
$1.2 billion for hedging, transaction and restructuring costs. In 2021, cash and cash equivalents
$2.0 billion to $5.0 billion.

At December 31, 2021, we had cash and cash equivalents of $5.0 billion, short-term inves
billion and available borrowing capacity under our credit facility of $6.0 billion, totaling approxima
billion of liquidity. We believe current cash balances and cash generated by operations, together wit
other sources of funds as described below in the “Significant Changes in Capital” section, will be
meet our funding requirements in the near- and long-term, including our capital spending program,
payments and required debt payments.

Significant Changes in Capital

Operating Activities

In 2021, cash provided by operating activities was $17 billion, compared with $4.8 billion f
increase is primarily due to higher realized commodity prices and higher sales volumes, mostly resulti
acquisition of Concho. The increase was partly offset by the $0.8 billion in settlement of oil and gas he
acquired from Concho, and approximately $0.4 billion of transaction and restructuring cost

Our short- and long-term operating cash flows are highly dependent upon prices for crude
natural gas, LNG and NGLs. Prices and margins in our industry have historically been volatile and
market conditions over which we have no control. Absent other mitigating factors, as these prices
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
production. Full-year production averaged 1,567 MBOED in 2021. Full-year production excluding Libya averaged
Adjusting for closed acquisitions and dispositions, impacts from 2020 curtailments, 2021 W
and the conversion of Concho two-stream contracted volumes to a three-stream basis, production i
2 percent or MBOED. First quarter 2022 production is expected to be 1.75 MMBOED to 1.79 MMBOED
production is subject to numerous uncertainties, including, among others, the volatile crude oil and natu
environment, which may impact investment decisions; the effects of price changes on proc
and variable-royalty contracts; acquisition and disposition of fields; field production decline rate
operating efficiencies; timing of startups and major turnarounds; political instability; weath

and the addition of proved reserves through exploratory success and their timely and cost-
development. While we actively manage these factors, production levels can cause variabi
flows, although generally this variability has not been as significant as that caused by commodity

To maintain or grow our production volumes on an ongoing basis, we must continue to add
base. Our proved reserves generally increase as prices rise and decrease as prices decline
replacement represents the net change in proved reserves, net of production, divided by our current ye
information on proved reserves, including both developed and undeveloped reserves, *see the reserves table*
disclosures contained in "Supplementary Data – Oil and Gas Operations." See "Item 1A—Risk Factors – U
successfully develop our resources, the scope of our business will decline, resulting in an a
business."

As discussed in the "Critical Accounting Estimates" section, engineering estimates of prove
imprecise; therefore, reserves may be revised upward or downward each year due to the i
changes in commodity prices or as more technical data becomes available on reservoirs. It is not poss
predict how revisions will impact future reserve quantities.

Investing Activities

In 2021, we invested $5.3 billion in capital expenditures. Capital expenditures invested in
were $4.7 billion and $6.6 billion, respectively. For information about our capital expenditures a
see the "Capital Expenditures and Investments" section.

In December 2021, we completed our acquisition of Shell's assets in the Delaware Basin fo
consideration of approximately $8.7 billion after customary adjustments. We funded this transaction with c
We completed our acquisition of Concho on January 15, 2021. The assets acquired in the trans
$382 million of cash. The net impact of these items is recognized within "Acquisition of business
acquired" on our consolidated statement of cash flows. *See Note 3.*

In 2021, we announced a disposition target of $4 to $5 billion in disposition proceeds by y
Only proceeds from transactions announced or initiated in the third quarter of 2021 or later will
toward this target. The proceeds from these transactions will be used in accordance with the company
including returns of capital to shareholders and reduction of gross debt. To date, we have achieved
the sale of noncore assets in our Lower 48 segment.

Total proceeds from asset dispositions in 2021 were $1.7 billion. Including the $250 million
above, we also received cash proceeds of $1.14 billion from sales of our investment in CVE common s
million of contingent payments related to dispositions completed before 2021. *See Note 4.* In May 2021, we annc
and began a paced monetization of our investment in CVE with the plan to direct proceeds
existing share repurchase program. We expect to fully dispose of our CVE common shares by early
the sales pace will be guided by market conditions, and we retain discretion to adjust accordin *See Note 5.*

Proceeds from asset sales in 2020 were $1.3 billion. We received cash proceeds of $765 m
divestiture of our Australia-West assets and operations. We also received proceeds of $359 million and
sale of our Niobrara interests and Waddell Ranch interests in the Lower 48, respectively.

Proceeds from asset sales in 2019 were $3.0 billion, including $2.2 billion for the sale of tw
U.K. subsidiaries and $350 million for the sale of our 30 percent interest in the Greater Sunrise *See Note 3.*

We invest in short-term investments as part of our cash investment strategy, the primary o
which is to protect principal, maintain liquidity and provide yield and total returns; these investments
deposits, commercial paper, as well as debt securities classified as available for sale. Funds for short
support our operating plan and provide resiliency to react to short-term price volatility are investe
instruments with maturities within the year. Funds we consider available to maintain resili

price downturns and to capture opportunities outside a given operating plan may be invest instruments with maturities greater than one year. *See Note 12*.

Financing Activities

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

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

The revolving credit facility supports ConocoPhillips Company's ability to issue up to $6.0 b commercial paper, which is primarily a funding source for short-term working capital needs. Commerci maturities are generally limited to 90 days. With no commercial paper outstanding and no direct borrowi credit, we had access to $6.0 billion in available borrowing capacity under the revolving credit fac December 31, 2021.

On January 15, 2021, we completed the acquisition of Concho in an all-stock transaction. I acquisition, we assumed Concho's publicly traded debt and in December 2020, we launched an offer to exc publicly traded debt for debt issued by ConocoPhillips. There were no impacts to ConocoPh rating as a result of the debt exchange. In June 2021, we reaffirmed our commitment to preserving o balance sheet by restating our intent to reduce gross debt by $5 billion over the next five years, dr efficient and resilient capital structure. See *Note 9* and *Note 3*.

On January 25, 2021, S&P revised the industry risk assessment for the E&P industry to 'Mo from 'Intermediate' based on a view of increasing risks from the energy transition, price volatilit profitability. On February 11, 2021, S&P downgraded its rating of our long-term debt from "A-" with a "stable" outlook and affirmed this rating in November 2021. In October 2021, Moody's affi rating of our long-term debt and revised its outlook from "stable" to "positive". In December 2021, its rating of our long-term debt as "A" with a "stable" outlook.

We do not have any ratings triggers on any of our corporate debt that would cause an auto and thereby impact our access to liquidity, upon downgrade of our credit ratings. If our credit r downgraded from their current levels, it could increase the cost of corporate debt available to us and re to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us the commercial paper market, we would still be able to access funds under our revolving credit

Certain of our project-related contracts, commercial contracts and derivative instruments c provisions requiring us to post collateral. Many of these contracts and instruments permit us to post letters of credit as collateral. At December 31, 2021 and 2020, we had direct bank letters of credit o and $240 million, respectively, which secured performance obligations related to various purchase co incident to the ordinary conduct of business. In the event of credit ratings downgrades, we may be re additional letters of credit.

We have a universal shelf registration statement on file with the SEC under which we have sell an indeterminate amount of various types of debt and equity securities.

issue and

Capital Requirements

For information about our capital expenditures and investments, see the “Capital Expendit Investments” section.

Our debt balance at December 31, 2021, was $19.9 billion, an increase of $4.6 billion from December 31, 2020, driven by debt acquired as part of the Concho acquisition. Maturities (including payments for finance leases) due in 2022 of $1.1 billion will be paid from current cash bala generated by operations. *See Note 9*.

In December 2021, we announced our expected 2022 return of capital program and the in return of capital framework. The framework is structured to deliver a compelling, growing through-cycle dividend and share repurchases. It includes the addition of a discretionary VROC tier. The flexible tool for meeting our commitment of returning greater than 30 percent of cash from activities during periods where commodity prices are meaningfully higher than our planning price ra expected 2022 total capital returns at approximately $8 billion, consisting of distributions f these

Consistent with our commitment to deliver value to shareholders, in 2021, we paid $2.4 bi common stock, in ordinary dividends. This was an increase over 2020 and 2019, when we $1.34 per share of common stock, respectively. On February 3, 2022, we announced a quarterly divi payable March 1, 2022, to stockholders of record at the close of business on February 14, 2022, January 14, we paid the first VROC payment of $0.20 per share to shareholders of record as of J On February 3, 2022, we announced a VROC of $0.30 per share, payable on April 14, 2022, to record at the close of business on March 31, 2022.

The ordinary dividend and VROC are subject to numerous considerations and will be deter approved each quarter by the Board of Directors. We expect to announce the VROC when we annou dividend, but the quarterly payouts will be staggered from the ordinary dividend, resulting cash distributions throughout the year.

In late 2016, we initiated our current share repurchase program with Board of Director’s a $25 billion of our common stock. Share repurchases were $3.6 billion, $0.9 billion, and $3.5 bi 2019, and 2020, respectively. As of December 31, 2021, share repurchases since the inception of our program totaled 247 million shares and $14 billion. Repurchases are made at management’s discret prevailing prices, subject to market conditions and other factors.

For more information on factors considered when determining the levels of returns of capit *see "Item 1A—Risk Factors – Our ability to execute our capital return program is subject to certain considerati*

In addition to the priorities described above, we have contractual obligations to purchase g services of approximately $11.8 billion. We expect to fulfill $6 billion of these obligations in 2022. The excludes purchase commitments for jointly owned fields and facilities where we are not the operator obligations of $5.3 billion are related to agreements to access and utilize the capacity of third-party eq facilities, including pipelines and LNG product terminals, to transport, process, treat and store comm Obligations of $5.3 billion are related to market-based contracts for commodity product pu purchase third parties. The remainder is primarily our net share of purchase commitments for materials a jointly owned fields and facilities where we are the operator.

Capital Expenditures and Investments

	Millions of Dollars		
	2021	2020	2
Alaska	**$** 982	1,038	1,5
Lower 48	3,129	1,881	3,3
Canada	203	651	3
Europe, Middle East and North Africa	534	600	7
Asia Pacific	390	384	5
Other International	33	121	
Corporate and Other	53	40	
Capital Program*	**$ 5,324**	4,715	6,6

** Excludes capital related to acquisitions of businesses, net of capital acquired.*

Our capital expenditures and investments for the three-year period ended December 31, 2
$16.7 billion. The 2021 expenditures supported key exploration and developments, primar

- Development activities in the Lower 48, primarily Permian, Eagle Ford, and Bakken.
- Appraisal and development activities in Alaska related to the Western North Slope a activities in the Greater Kuparuk Area.
- Appraisal and development activities in the Montney and optimization of oil sands d Canada.
- Continued development activities across assets in Norway.
- Continued development activities in China, Malaysia, and Indonesia.

2022 Capital Budget

In December 2021, we announced our 2022 operating plan capital of $7.2 billion. The plar
funding for ongoing development drilling programs, major projects, exploration and appraisal activities
maintenance and $0.2 billion for projects to reduce the company's scope 1 and 2 emissions intensity and inv
several early-stage low-carbon opportunities that address end-use emissions.

Guarantor Summarized Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company, and Bur Resources LLC. With respect to publicly held debt securities. ConocoPhillips Company is 100 percent owne by ConocoPhillips. Burlington Resources LLC is 100 percent owned by ConocoPhillips Company. ConocoPhillip and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of Burlington with respect to its publicly held debt securities. Similarly, ConocoPhillips has fully and unconditi guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt secur In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several.

The following tables present summarized financial information for the Obligor Group, as de

- The Obligor Group will reflect guarantors and issuers of guaranteed securities consi ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC.
- Consolidating adjustments for elimination of investments in and transactions betwe guarantors and issuers of guaranteed securities are reflected in the balances of the financial information.
- Non-Obligated Subsidiaries are excluded from this presentation.

Upon completing the Concho acquisition on January 15, 2021, we assumed Concho's public of approximately $3.9 billion in aggregate principal amount, which was recorded at the fair va the acquisition date. We completed a debt exchange offer that settled on February 8, 2021 percent, approximately $3.8 billion in aggregate principal amount of Concho's notes, were tender new debt issued by ConocoPhillips. The new debt issued in the exchange is fully and uncor guaranteed by ConocoPhillips Company. Both the guarantor and issuer of the exchange debt is reflecte Obligor Group presented here. *See Note 3* and *Note 9*

Transactions and balances reflecting activity between the Obligors and Non-Obligated Subs presented separately below:

Summarized Income Statement Data	Millions of Do
	2021
Revenues and Other Income	**$** 30,
Income (loss) before income taxes*	8,
Net income (loss)	8,
Net Income (Loss) Attributable to ConocoPhillips	8,

**Includes approximately $5.4 billion of purchased commodities expense for transactions with Non-Obligated Su*

Summarized Balance Sheet Data	Millions of Do
	December 31
Current assets	**$** 7,
Amounts due from Non-Obligated Subsidiaries, current	1,
Noncurrent assets	69,
Amounts due from Non-Obligated Subsidiaries, noncurrent	7,
Current liabilities	8,
Amounts due to Non-Obligated Subsidiaries, current	3,
Noncurrent liabilities	30,
Amounts due to Non-Obligated Subsidiaries, noncurrent	13,

Contingencies

We are subject to legal proceedings, claims, and liabilities that arise in the ordinary course
We accrue for losses associated with legal claims when such losses are considered probable and the a
reasonably estimated. See "Critical Accounting Estimates" and *Note 1* for information on contingencies

Legal and Tax Matters

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

Our legal organization applies its knowledge, experience, and professional judgment to the
of our cases, characteristics employing a litigation management process to manage and monitor the legal
against us. Our process facilitates the early evaluation and quantification of potential exposures in indi
This process also enables us to track those cases that have been scheduled for trial and/or med
professional judgment and experience in using these litigation management tools and avail
about current developments in all our cases, our legal organization regularly assesses the adequa
accruals and determines if an adjustment of existing accruals, or establishment of new accruals, is *See Note*

Environmental

We are subject to the same numerous international, federal, state, and local environmenta
regulations as other companies in our industry. The most significant of these environmental laws and
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 Restrictio (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability A Superfund), which imposes liability on generators, transporters and arrangers of ha substances at sites where hazardous substance releases have occurred or are threatening to occu
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the tr storage, and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators o facilities and pipelines, lessees or permittees of an area in which an offshore facility is locate and operators of vessels are liable for removal costs and damages that result from a dis navigable waters of the U.S.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), whic facilities to report toxic chemical inventories with local emergency planning committees and res departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in u injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas ope waters and impose liability for the cost of pollution cleanup resulting from operations, as w 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 c water) establish water quality limits, and establish standards and impose obligations for the reme releases of hazardous substances and hazardous wastes. They also, in most cases, require permits in new or modified operations. These permits can require an applicant to collect substantial informat connection with the application process, which can be expensive and time-consuming. In addition, there ca associated with notice and comment periods and the agency's processing of the application. Many of 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 e laws and regulations governing these same types of activities. While similar, in some cases these re impose additional, or more stringent, requirements that can add to the cost and difficulty of marke transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither cle easily determinable as new standards, such as air emission standards and water quality standard evolve. However, environmental laws and regulations, including those that may arise to address co global climate change, are expected to continue to have an increasing impact on our operations i other countries in which we operate. Notable areas of potential impacts include air emission com remediation obligations in the U.S. and Canada.

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

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

We occasionally receive requests for information or notices of potential liability from the EP environmental agencies alleging that we are a potentially responsible party under CERCLA state statute. On occasion, we also have been made a party to cost recovery litigation by those private parties. These requests, notices and lawsuits assert potential liability for remediation costs that typically are not owned by us, but allegedly contain wastes attributable to our past operati December 31, 2021, there were 15 sites around the U.S. in which we were identified as a p responsible party under CERCLA and comparable state laws.

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

Expensed environmental costs were $632 million in 2021 and are expected to be about $6 $700 million in 2022 and 2023, respectively. Capitalized environmental costs were $184 m and are expected to be about $218 million and $316 million in 2022 and 2023, respectively.

Accrued liabilities for remediation activities are not reduced for potential recoveries from in third parties and are not discounted (except those assumed in a purchase business combination a discounted basis).

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

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

At December 31, 2021, our balance sheet included total accrued environmental costs of $1 compared with $180 million at December 31, 2020, for remediation activities in the U.S. and Canada 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 bus environmental costs and liabilities are inherent concerns in our operations and products, and there can be 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 e laws and regulations.

See Item 1A—Risk Factors – We expect to continue to incur substantial capital expenditure costs as a result of our compliance with existing and future environmental laws and regulations and *Note 1* for inform on environmental litigation.

Climate Change

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

- European Emissions Trading Scheme (ETS), the program through which many of the states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2021 w approximately $19 million (net share before-tax).
- U.K. Emissions Trading Scheme, the program with which the U.K. has replaced the compliance with the U.K. ETS in 2021 was approximately $2.8 million (net share be
- The Alberta Technology Innovation and Emissions Reduction (TIER) regulation requi facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or per year to meet a facility benchmark intensity. The total cost of these regulations in 2021 w approximately $1 million (net share before-tax).
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. confirmed that the EPA has the authority to regulate carbon dioxide as an "air pollutant" unde the Clean Air Act.
- The U.S. EPA's announcement on March 29, 2010 (published as "Interpretation of R Determine Pollutants Covered by Clean Air Act Permitting Programs," 75 Fed. Reg. 2010)), and the EPA's and U.S. Department of Transportation's joint promulgation of a Fina 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate- 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 pla address methane and smog-forming volatile organic compound emissions from the oil and g
- The U.S. government has announced on September 17, 2021 the Global Methane P initiative to reduce global methane emissions by at least 30 percent from 2020 leve
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbo 2021 were fees of approximately $35 million (net share before-tax). We also incur a carb emissions from fossil fuel combustion in our British Columbia and Alberta operations in Canad approximately $5.7 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the U Nations Framework Convention on Climate Change, setting out a process for achiev emissions reduction. The new administration has recommitted the United States to the Paris a significant number of U.S. state and local governments and major corporations hea the U.S. have also announced related commitments. Accordingly, the U.S. administration se April 22, 2021 of a 50 to 52 percent reduction in GHG emissions from 2005 levels in

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

Compliance with changes in laws and regulations that create a GHG tax, emission trading s
reduction policies could significantly increase our costs, reduce demand for fossil energy de
impact the cost and availability of capital and increase our exposure to litigation. Such laws and r
also increase demand for less carbon intensive energy sources, including natural gas. The ultim
our financial performance, either positive or negative, will depend on a number of factors, inclu
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
- 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 sever events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflect of our products and services.

See Item 1A—Risk Factors – Existing and future laws, regulations and internal initiatives re climate changes, such as limitations on GHG emissions may impact or limit our business plans, res expenditures, promote alternative uses of energy or reduce demand for our products and *Note 1* for informat on climate change litigation.

<u>Company Response to Climate-Related Risks</u>
The company has responded by putting in place a Sustainable Development Risk Managem
covering the assessment and registration of significant and high sustainable development risks base
consequence and likelihood of occurrence. We have developed a company-wide Climate Change Action P
goal of tracking mitigation activities for each climate-related risk included in the corporate Sustain
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 three different scopes. Gross operated and net equity Scope
GHG emissions help us understand our climate transition risk.

- Scope 1 emissions are direct GHG emissions from sources that we control or in wh ownership interest.
- Scope 2 emissions are indirect GHG emissions from the generation of purchased e steam that we consume.
- Scope 3 emissions are indirect emissions from sources that we neither own nor co

We announced in October 2020 the adoption of a Paris-aligned climate risk framework with
implementing a coherent set of choices designed to facilitate the success of our existing ex
production business through the energy transition. Given the uncertainties remaining abou
energy transition will evolve, the strategy aims to be robust across a range of potential future out

The strategy is comprised of four pillars:

- Targets: Our target framework consists of a hierarchy of targets, from a long-term a sets the direction and aim of the strategy, to a medium-term performance target for GHG er intensity, to shorter-term targets for flaring and methane intensity reductions. These performan supported by lower-level internal business unit goals to enable the company to achi company-wide targets. In September 2021, we increased our interim operational target and reduce our gross operated and net equity (scope 1 and 2) emissions intensity by 40 to 50 p 2016 levels by 2030, an improvement from the previously announced target of 35 to 45 p a gross operated basis, with an ambition to achieve net-zero operated emissions by 2050. W the World Bank Flaring Initiative to work towards zero routine flaring of associated gas ambition to meet that goal by 2025.
- Technology choices: We expanded our Marginal Abatement Cost Curve process to p range of opportunities for emission reduction technology.
- Portfolio choices: Our corporate authorization process requires all qualifying project GHG price in their project approval economics. Different GHG prices are used depending our jurisdiction. Projects in jurisdictions with existing GHG pricing regimes incorporate t price and forecast into their economics. Projects where no existing GHG pricing regime e scenario forecast from our internally consistent World Energy Model. In this way, both existi regulatory requirements are considered in our decision-making. The company does estimated market cost of GHG emissions when assessing reserves in jurisdictions without exis regulations. This is in contrast to changes to the cost of existing GHG emission regulations whicl reserves calculations.
- External engagement: Our external engagement aims to differentiate ConocoPhillips and gas sector with our approach to managing climate-related risk. We are a Founding Climate Leadership Council (CLC), an international policy institute founded in collab business and environmental interests to develop a carbon dividend plan. Participation in the another opportunity for ongoing dialogue about carbon pricing and framing the issues in alig public policy principles. We also belong to and fund Americans For Carbon Dividends, the advocacy branch of the CLC.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to s appropriate accounting policies and to make estimates and assumptions that affect the reported amour liabilities, revenues, and expenses. *See Note 1* for descriptions of our major accounting policies. Certain of t policies involve judgments and uncertainties to such an extent there is a reasonable likelih different amounts would have been reported under different conditions, or if different assumptions h These critical accounting estimates are discussed with the Audit and Finance Committee of the Bo at least annually. We believe the following discussions of critical accounting estimates address all i accounting areas where the nature of accounting estimates or assumptions is material due to the leve and judgment necessary to account for highly uncertain matters or the susceptibility of such m

Oil and Gas Accounting

Accounting for oil and gas activity is subject to special accounting rules unique to the oil ar The acquisition of G&G seismic information, prior to the discovery of proved reserves, is expens similar to accounting for research and development costs. However, leasehold acquisition costs ar well costs are capitalized on the balance sheet pending determination of whether proved oil and have been recognized.

<u>Property Acquisition Costs</u>

At year-end 2021, we held $9.3 billion of net capitalized unproved property costs which co of individually significant and pooled leaseholds, mineral rights held in perpetuity by title own exploratory wells currently being drilled, and to a lesser extent, suspended exploratory wells and capita This amount increased by $6.9 billion at December 31, 2021 as compared to December 31, 202 to the Concho and Shell Permian acquisitions in the Permian Basin where we have an ongoing sig active development program. Outside of the Permian Basin, the remaining $2.0 billion is concent development areas. Management periodically assesses our unproved property for impairm the results of exploration and drilling efforts and the outlook for commercialization.

For individually significant leaseholds, management periodically assesses for impairment b exploration and drilling efforts to date. For insignificant individual leasehold acquisition costs, management judgment determines a percentage probability that the prospect ultimately will fail to find proved reserves, including estimates of future expirations, and pools that leasehold information with others geographic areas. For prospects in areas with limited, or no, previous exploratory drilling, the percenta of ultimate failure is normally judged to be quite high. This judgmental percentage is multipli leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to d periodic leasehold impairment charge that is reported in exploration expense. This judgmental prol percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favor unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment expense is adjusted prospectively.

<u>Exploratory Costs</u>

For exploratory wells, drilling costs are temporarily capitalized, or “suspended,” on the bala pending determination of whether potentially economic oil and gas reserves have been discovered b effort to justify development.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs
capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic a
viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental a
rules do not prohibit continued capitalization of suspended well costs on the expectation future
conditions or new technologies will be found that would make the development economically
Often, the ability to move into the development phase and record proved reserves is dependent on ob
government or co-venturer approvals, the timing of which is ultimately beyond our control
well costs remain suspended as long as we are actively pursuing such approvals and permits, and be
obtained. Once all required approvals and permits have been obtained, the projects are mo
development phase, and the oil and gas reserves are designated as proved reserves.

At year-end 2021, total suspended well costs were $660 million, compared with $682 millio
2020. For additional information on suspended wells, including an aging analysis, see Note 6.

<u>Proved Reserves</u>

Engineering estimates of the quantities of proved reserves are inherently imprecise and rep
approximate amounts because of the judgments involved in developing such information.
estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the pr
historical extraction recovery and processing yield factors, installed plant operating capacity and app
limits. The reliability of these estimates at any point in time depends on both the quality and quan
technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require d
"proved" reserve estimates due to the importance of these estimates to better understand the perce
future cash flows of a company's operations. There are several authoritative guidelines regarding
criteria that must be met before estimated reserves can be designated as "proved." Our geoscienc
engineering organization has policies and procedures in place consistent with these author
guidelines. We have trained and experienced internal engineering personnel who estimate our proved rese
consolidated companies, as well as our share of equity affiliates. See Oil and Gas supplem
for additional information.

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

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

The estimation of proved reserves is also important to the income statement because the p
estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of t
costs for that asset. At year-end 2021, the net book value of productive PP&E subject to a unit-o
calculation was approximately $52 billion and the DD&A recorded on these assets in 2021 was approx
billion. The estimated proved reserves for our consolidated operations were 2.5 billion BOE at the end
BOE at the end of 2021. If the estimates of proved reserves used in the unit-of-production
had been lower by 10 percent across all calculations, before-tax DD&A in 2021 would have increased
estimated $574 million.

Business Combination—Valuation of Oil and Gas Properties

For recent transactions, management applied the principles of acquisition accounting unde Topic 805 "Business Combinations" and allocated the purchase price to assets acquired and liabilities on their estimated fair values as of the acquisition date. Estimating the fair values involved m assumptions, of which the most significant assumptions relate to the fair values assigned t unproved oil and gas properties. Management utilized a discounted cash flow approach, based on ma assumptions, and engaged third party valuation experts in preparing fair value estimates.

Significant inputs incorporated within the valuation include future commodity price assump production profiles of reserve estimates, the pace of drilling plans, future operating and development rates, and discount rates using a market-based weighted average cost of capital determined at t acquisition. When estimating the fair value of unproved properties, additional risk-weightin are applied to probable and possible reserves.

The assumptions and inputs incorporated within the fair value estimates are subject to con judgement and are based on industry, market, and economic conditions prevalent at the ti acquisition. Although we based these estimates on assumptions believed to be reasonable, these estim inherently unpredictable and uncertain and actual results could differ. *See Note 3*

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in fac circumstances indicate a possible significant deterioration in the future cash flows expected to be generat group. If there is an indication the carrying amount of an asset may not be recovered, a recoverabili performed using management's assumptions for prices, volumes and future development plans. If the undiscounted cash flows before income-taxes is less than the carrying value of the asset g carrying value is written down to estimated fair value and reported as an impairment in the periods in wh determined. Individual assets are grouped for impairment purposes at the lowest level for which identifiable cash flows that are largely independent of the cash flows of other groups of assets—genera basis by field for E&P assets. Because there usually is a lack of quoted market prices for long-lived value of impaired assets is typically determined based on the present values of expected future cas discount rates and prices believed to be consistent with those used by principal market participants, multiple of operating cash flow validated with historical market transactions of similar assets where

The expected future cash flows used for impairment reviews and related fair value calculat on estimated future production volumes, commodity prices, operating costs and capital decisi all available evidence at the date of review. Differing assumptions could affect the timing and an impairment in any period. *See Note 6* and *Note 7*.

Investments in nonconsolidated entities accounted for under the equity method are assess impairment whenever changes in the facts and circumstances indicate a loss in value has occurred. Su loss in value might include our inability to recover the carrying amount, the lack of sustained earn which would justify the current investment amount, or a current fair value less than the investme amount. When such a condition is judgmentally determined to be other than temporary, an impairm recognized for the difference between the investment's carrying value and its estimated fa determining whether a decline in value is other than temporary, management considers fac length of time and extent of the decline, the investee's financial condition and near-term prospect ability and intent to retain our investment for a period that will be sufficient to allow for any anticip the market value of the investment. Since quoted market prices are usually not available, the typically based on the present value of expected future cash flows using discount rates and prices b consistent with those used by principal market participants, plus market analysis of comparable asset investee, if appropriate. Differing assumptions could affect the timing and the amount of a an investment in any period. See the "APLNG" section of *Note 4*

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to ren equipment and restore the land or seabed at the end of operations at operational sites. Ou removal obligations involve plugging and abandonment of wells, removal and disposal of offshore o platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. Fair va using a present value approach, incorporating assumptions about estimated amounts and timing o and impacts of the use of technologies. Estimating future asset removal costs requires significa Most of these removal obligations are many years, or decades, in the future and the contracts and often have vague descriptions of what removal practices and criteria must be met when the removal e occurs. The carrying value of our asset retirement obligation estimate is sensitive to inputs such a technologies and costs, regulatory and other compliance considerations, expenditure timing inputs into valuation of the obligation, including discount and inflation rates, which are all subject to c the time of initial recognition of the liability and future settlement of our obligation.

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

In addition to asset removal obligations, under the above or similar contracts, permits and have certain environmental-related projects. These are primarily related to remediation activitie Canada and various states within the U.S. at exploration and production sites. Future environment costs are difficult to estimate because they are subject to change due to such factors as the uncerta cleanup costs, the unknown time and extent of such remedial actions that may be required, and th of our liability in proportion to that of other responsible parties. *See Note 8*

Projected Benefit Obligations

The actuarial determination of projected benefit obligations and company contribution requ involves judgment about uncertain future events, including estimated retirement dates, salary level mortality rates, lump-sum election rates, rates of return on plan assets, future health care rates, and rates of utilization of health care services by retirees. Due to the specialized nature of thes we engage outside actuarial firms to assist in the determination of these projected benefit obli company contribution requirements. Ultimately, we will be required to fund all vested benefits under postretirement benefit plans not funded by plan assets or investment returns, but the judg assumptions used in the actuarial calculations significantly affect periodic financial statements and fundi time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 1 decrease in the discount rate assumption would increase projected benefit obligations by $1.0 billion expense is sensitive to the discount rate and return on plan assets assumptions. A 100 basis-point de discount rate assumption would increase annual benefit expense by $70 million, while a 100 basis-p the return on plan assets assumption would increase annual benefit expense by $60 million. In the discount rate, we use yields on high-quality fixed income investments matched to the estir cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits take plans during the year could exceed the total of service and interest components of annual pensio trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. payments are based on decisions by plan participants and are therefore difficult to predict. there is a significant reduction in the expected years of future service of present employees or the el accrual of defined benefits for some or all of their future services for a significant number of emplo recognize a curtailment gain or loss. *See Note 16*

Contingencies

A number of claims and lawsuits are made against the company arising in the ordinary cou
Management exercises judgment related to accounting and disclosure of these claims whic
losses, damages, and underpayments associated with environmental remediation, tax, contracts, cases, disputes. As we learn new facts concerning contingencies, we reassess our position both with respec recognized and disclosed considering changes to the probability of additional losses and po exposure. However, actual losses can and do vary from estimates for a variety of reasons including le third-party or other decisions; settlement discussions; evaluation of scope of damages; interpretati or contractual terms; expected timing of future actions; and proportion of liability shared with responsible parties. Estimated future costs related to contingencies are subject to change as events ev additional information becomes available during the administrative and litigation processes. For addit information on contingent liabilities, see the "Contingencies" section within "Capital Resources and Liquidit *Note 11*

Income Taxes

We are subject to income taxation in numerous jurisdictions worldwide. We record deferre liabilities to account for the expected future tax consequences of events that have been rec financial statements and our tax returns. We routinely assess our deferred tax assets and reduce su valuation allowance if we deem it is more likely than not that some portion, or all, of the deferred ta be realized. In assessing the need for adjustments to existing valuation allowances, we consi positive and negative evidence. Positive evidence includes reversals of temporary differences, forec taxable income, assessment of future business assumptions and applicable tax planning strategies prudent and feasible. Negative evidence includes losses in recent years as well as the forecasts of futur (loss) the realizable period. In making our assessment regarding valuation allowances, we weigh based on objectivity. Numerous judgments and assumptions are inherent in the determination of fut including factors such as future operating conditions and the assessment of the effects of f federal US income taxes (particularly as related to prevailing oil and gas prices). *See Note 17*

We regularly assess and, if required, establish accruals for uncertain tax positions that cou assessments of additional tax by taxing jurisdictions in countries where we operate. We re benefit from an uncertain tax position when it is more likely than not that the position will be susta examination, based on the technical merits of the position. These accruals for uncertain tax positions are significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing circumstances considering the progress of ongoing tax audits, court proceedings, changes laws, including tax case rulings and legislative guidance, or expiration of the applicable statute o *See Note 17* regarding discussion of critical accounting estimates on deferred tax valuation allowance

Cautionary Statement for the Purposes of the “Safe Harbor” Pro the Private Securities Litigation Reform Act of 1995

This report includes forward-looking statements within the meaning of Section 27A of the S 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than stateme fact included or incorporated by reference in this report, including, without limitation, statemen future financial position, business strategy, budgets, projected revenues, projected costs and plar management for future operations and the anticipated impact of the Shell Enterprise LLC (transaction on the company's business and future financial and operating results are forward-looking stateme forward-looking statements contained in this report include our expected production growt the business environment generally, our expected capital budget and capital expenditures, and concerning future dividends. You can often identify our forward-looking statements by the words “anticipate,” “believe,” “budget,” “continue,” “could,” “effort,” “estimate,” “expect,” “forecast,” “intend,” “goal,” “gu “objective,” “outlook,” “plan,” “potential,” “predict,” “projection,” “seek,” “should,” “target,” and similar expressions.

We based the forward-looking statements on our current expectations, estimates and proj our business and the industries in which we operate in general. We caution you these statements are no future performance as they involve assumptions that, while made in good faith, may prove to be involve risks and uncertainties we cannot predict. In addition, we based many of these forward-lo statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual results may differ materially from what we have expressed or forecast in the forward-looking state differences could result from a variety of factors and uncertainties, including, but not limited to, the fo

- The impact of public health crises, including pandemics (such as COVID-19) and ep related company or government policies or actions.
- Global and regional changes in the demand, supply, prices, differentials or other ma affecting oil and gas, including changes resulting from a public health crisis or from the lifting of crude oil production quotas or other actions that might be imposed by OPE producing countries and the resulting company or third-party actions in response to such char
- Fluctuations in crude oil, bitumen, natural gas, LNG and NGLs prices, including a pr in these prices relative to historical or future expected levels.
- The impact of significant declines in prices for crude oil, bitumen, natural gas, LNG may result in recognition of impairment charges on our long-lived assets, leaseholds and nonconsolidated equity investments.
- The potential for insufficient liquidity or other factors, such as those described herei impact our ability to repurchase shares and declare and pay dividends, whether fixed or va
- Potential failures or delays in achieving expected reserve or production levels from future oil and gas developments, including due to operating hazards, drilling risks and the inh uncertainties in predicting reserves and reservoir performance.
- Reductions in reserves replacement rates, whether as a result of the significant dec commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to explora
- Unexpected changes in costs or technical requirements for constructing, modifying facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including addressing the impact of global climate change or further regulating hydraulic fracturing, meth flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitu gas, LNG and NGLs.
- Inability to timely obtain or maintain permits, including those necessary for constru development, or inability to make capital expenditures required to maintain complia necessary permits or applicable laws or regulations.

- Failure to complete definitive agreements and feasibility studies for, and to complete
of, announced and future E&P and LNG development in a timely manner (if at all) or on
- Potential disruption or interruption of our operations due to accidents, extraordinary
events, supply chain disruptions, civil unrest, political events, war, terrorism, cyber attacks,
technology failures, constraints or disruptions.
- Changes in international monetary conditions and foreign currency exchange rate fl
- Changes in international trade relationships, including the imposition of trade restri
relating to crude oil, bitumen, natural gas, LNG, NGLs and any materials or product
aluminum) used in the operation of our business.
- Substantial investment in and development use of, competing or alternative energy
including as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under
future environmental regulations and litigation.
- Significant operational or investment changes imposed by existing or future enviror
and regulations, including international agreements and national or regional legislation a
measures to limit or reduce GHG emissions.
- Liability resulting from litigation, including litigation directly or indirectly related to t
with Concho Resources Inc., or our failure to comply with applicable laws and regulations
- General domestic and international economic and political developments, including
hostilities, expropriation of assets; changes in governmental policies relating to crude oil, bitur
gas, NGLs, LNG pricing; regulation or taxation; and other political, economic or diplomatic
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates)
applicable to our business.
- 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 a
illiquidity or uncertainty in domestic or international financial markets or investment sentimer
- Our inability to execute, or delays in the completion, of any asset dispositions or ac
elect to pursue.
- Potential failure to obtain, or delays in obtaining, any necessary regulatory approva
future asset dispositions or acquisitions, or that such approvals may require modific
the terms of the transactions or the operation of our remaining business.
- Potential disruption of our operations as a result of pending or future asset dispositi
acquisitions, including the diversion of management time and attention.
- Our inability to deploy the net proceeds from any asset dispositions that are pendin
elect to undertake in the future in the manner and timeframe we currently anticipate, if at a
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their ob
including our ability to collect payments when due from the government of Venezue
- Our inability to realize anticipated cost savings and capital expenditure reductions.
- The inadequacy of storage capacity for our products, and ensuing curtailments, whe
or involuntary, required to mitigate this physical constraint.
- The risk that we will be unable to retain and hire key personnel.
- Unanticipated integration issues relating to the acquisition of assets from Shell, suc
disruptions of our ongoing business and higher than anticipated integration costs.
- Uncertainty as to the long-term value of our common stock.
- The diversion of management time on integration-related matters.
- The factors generally described in *Item 1A—Risk Factors* in this 2021 Annual Report on Form 1
additional risks described in our other filings with the SEC.

Item 7A. Quantitative and Qualitative Disclosures about Market

Financial Instrument Market Risk

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

Our use of derivative instruments is governed by an "Authority Limitations" document appr
Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments w
liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limit
company, and compliance with these limits is monitored daily. The Executive Vice President and Chief Fin
who reports to the Chief Executive Officer, monitors commodity price risk and risks resulting fro
currency exchange rates and interest rates. The Commercial organization manages our commercial
optimizes commodity flows and positions, and monitors risks.

Commodity Price Risk

Our Commercial organization uses futures, forwards, swaps and options in various market
the following objectives:

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

We use a VaR model to estimate the loss in fair value that could potentially result on a sing
effect of adverse changes in market conditions on the derivative financial instruments and derivativ
instruments we hold or issue, including commodity purchases and sales contracts recorded
Sheet at December 31, 2021, as derivative instruments. Using Monte Carlo simulation, a 95 percen
level and a one-day holding period, the VaR for those instruments issued or held for trading purposes
purposes other than trading at December 31, 2021 and 2020, was immaterial to our consolidated ca
income attributable to ConocoPhillips.

Interest Rate Risk

The following table provides information about our debt instruments that are sensitive to c
interest rates. The table presents principal cash flows and related weighted-average interest rates
maturity dates. Weighted-average variable rates are based on effective rates at the reporting date.
amount of our floating-rate debt approximates its fair value. A hypothetical 10 percent change in pre
rates would not have a material impact on interest expense associated with our floating-rate deb
the fixed-rate debt is measured using prices available from a pricing service that is corroborate
data. Changes to prevailing interest rates would not impact our cash flows associated with fixed
unless we elect to repurchase or retire such debt prior to maturity.

Expected Maturity Date	Millions of Dollars Except as Indicate Debt Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Ave Inte R
Year-End 2021				
2022	**$ 346**	**2.53%**	**$ 500**	**1**
2023	**116**	**6.64**	**-**	
2024	**459**	**3.51**	**-**	
2025	**369**	**5.32**	**-**	
2026	**1,355**	**5.06**	**-**	
Remaining years	**14,338**	**5.80**	**283**	**0**
Total	**$ 16,983**		**$ 783**	
Fair value	**$ 21,668**		**$ 783**	
Year-End 2020				
2021	$ 133	8.47%	$ 300	0
2022	346	2.53	500	1
2023	110	7.03	-	
2024	459	3.51	-	
2025	368	5.33	-	
Remaining years	11,793	6.28	283	0
Total	$ 13,209		$ 1,083	
Fair value	$ 18,023		$ 1,083	

Foreign Currency Exchange Risk
We have foreign currency exchange rate risk resulting from international operations. We d
comprehensively hedge the exposure to currency exchange rate changes although we may choose to selecti
certain foreign currency exchange rate exposures, such as firm commitments for capital projects c
tax payments, dividends and cash returns from net investments in foreign affiliates to be remit
coming year, and investments in equity securities.

At December 31, 2021 and 2020, we held foreign currency exchange forwards hedging cro
activity and foreign currency exchange swaps for purposes of mitigating our cash-related e
Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected n
hedge accounting. As a result, the change in the fair value of these foreign currency exchange de
recorded directly in earnings.

At December 31, 2021, we had outstanding foreign currency exchange forward contracts t
billion AUD at $0.715 AUD against the U.S. dollar. At December 31, 2020, we had outstanding foreign cu
exchange forward contracts to sell $0.45 billion CAD at $0.748 CAD against the U.S. dollar. Based on the ass
in the fair value calculation, the net fair value of these foreign currency contracts at December 31, 20
December 31, 2020, were a before-tax gain of $21 million and before-tax loss of $16 million, respectively
hypothetical 10 percent change in the December 2021 and December 2020 exchange rate,
result in an additional before-tax loss of $134 million and $39 million, respectively. The sensitivity ana
changing one assumption while holding all other assumptions constant, which in practice m
to occur, as changes in some of the assumptions may be correlated.

The gross notional and fair value of these positions at December 31, 2021 and 2020, were

Foreign Currency Exchange Derivatives		In Millions			
		Notional		Fair Value*	
		2021	2020	**2021**	2
Sell Canadian dollar, buy U.S. dollar	CAD	**-**	450	**-**	(
Buy Canadian dollar, sell U.S. dollar	CAD	**77**	80	**(1)**	
Buy Australian dollar, sell U.S. dollar	AUD	**1,850**	-	**21**	
Sell British pound, buy euro	GBP	**239**	8	**(8)**	
Buy British pound, sell euro	GBP	**394**	3	**7**	

**Denominated in USD.*

For additional information about our use of derivative instruments, *see Note 12*

Item 8. Financial Statements and Supplementary Data

ConocoPhillips

Index to Financial Statements

Reports of Management

Management prepared, and is responsible for, the consolidated financial statements and th
information appearing in this annual report. The consolidated financial statements present fairly the co
financial position, results of operations and cash flows in conformity with accounting principles gene
the United States. In preparing its consolidated financial statements, the company includes am
based on estimates and judgments management believes are reasonable under the circumstances. T
financial statements have been audited by Ernst & Young LLP, an independent registered public acco
appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders.
has made available to Ernst & Young LLP all of the company's financial records and related data
minutes of stockholders' and directors' meetings.

Assessment of Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of the company's internal control over financial re
December 31, 2021. In making this assessment, it used the criteria set forth by the Comm
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 effectiv
December 31, 2021. Management's assessment of, and conclusion on, the effectiveness of
over financial reporting did not include the internal controls of the assets acquired from Shell En
December 2021. The total assets acquired represented approximately 10 percent of the co
total consolidated assets at December 31, 2021.

Ernst & Young LLP has issued an audit report on the company's internal control over financ
of December 31, 2021, and their report is included herein.

/s/ Ryan M. Lance	/s/ William L. Bullock, Jr.
Ryan M. Lance	**William L. Bullock, Jr.**
Chairman and Chief Executive Officer	Executive Vice President and Chief Financial Officer

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 Com
December 31, 2021 and 2020, the related consolidated income statement, consolidated statements o
income, changes in equity and cash flows for each of the three years in the period ended D
2021, and the related notes (collectively referred to as the "consolidated financial statements"). In ou
consolidated financial statements present fairly, in all material respects, the financial positi
Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for ea
years in the period ended December 31, 2021, in conformity with U.S. generally accepted accounti

We also have audited, in accordance with the standards of the Public Company Accounting
(United States) (PCAOB), the Company's internal control over financial reporting as of Dec
based on criteria established in Internal Control–Integrated Framework issued by the Committee
Organizations of the Treadway Commission (2013 framework) and our report dated Februa
expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our respo
express an opinion on the Company's financial statements based on our audits. We are a public accour
registered with the PCAOB and are required to be independent with respect to the Company in accorc
U.S. federal securities laws and the applicable rules and regulations of the Securities and Excha
and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards
plan and perform the audit to obtain reasonable assurance about whether the financial stateme
material misstatement, whether due to error or fraud. Our audits included performing procedures to
risks of material misstatement of the financial statements, whether due to error or fraud, and perfo
procedures that respond to those risks. Such procedures included examining, on a test basis, evidence rega
amounts and disclosures in the financial statements. Our audits also included evaluating the accounting
and significant estimates made by management, as well as evaluating the overall presentation
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
consolidated financial statements that were communicated or required to be communicated
and Finance Committee and that: (1) relate to accounts or disclosures that are material to the
financial statements and (2) involved our especially challenging, subjective or complex judgments.
communication of critical audit matters does not alter in any way our opinion on the consolidated financial sta
as a whole, and we are not, by communicating the critical audit matters below, providing separ
the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for asset retirement obligations for certain offshore p

Description of the Matter	At December 31, 2021, the asset retirement obligation (ARO) balance to billion. As further described in Note 8, the Company records AROs in the period in incurred, typically when the asset is installed at the production location. of obligations related to certain offshore assets requires significant judgmer magnitude and higher estimation uncertainty related to plugging and ab wells and removal and disposal of offshore oil and gas platforms, facilities and (collectively, removal costs). Furthermore, given certain of these assets a end of their operations, the impact of changes in these AROs may result in a to earnings given the relatively short remaining useful lives of the assets. Auditing the Company's AROs for the obligations identified above is comp judgmental due to the significant estimation required by management in obligations. In particular, the estimates were sensitive to significant subj assumptions such as removal cost estimates and end of field life, which are affected b about future market or economic conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the ope effectiveness of the Company's internal controls over its ARO estimation process, inclu management's review of the significant assumptions that have a material effect on the the obligations. We also tested management's controls over the completenes of the financial data used in the valuation. To test the AROs for the obligations identified above, our audit procedure among others, assessing the significant assumptions and inputs used in the valu removal cost estimates and end of field life assumptions. For example, w removal cost estimates by comparing to settlements and recent removal costs. We also compared end of field life assumptions to production forecasts.

Depreciation, depletion and amortization of proved oil and gas pr plants and equipment

Description of the Matter	At December 31, 2021, the net book value of the Company's proved oil a properties, plants and equipment (PP&E) was $52 billion, and depreciation, depletior amortization (DD&A) expense was $7.0 billion for the year then ended. As described i the successful efforts method of accounting, DD&A of PP&E on producing hyc properties and steam-assisted gravity drainage facilities and certain pipe natural gas assets (those which are expected to have a declining utilizati determined by the unit-of-production method. The unit-of-production me proved oil and gas reserves, as estimated by the Company's internal reservoir e Proved oil and gas reserve estimates are based on geological and engine assessments of in-place hydrocarbon volumes, the production plan, historical extractic processing yield factors, installed plant operating capacity and approved Significant judgment is required by the Company's internal reservoir eng evaluating geological and engineering data when estimating proved oil and gas rese proved oil and gas reserves also requires the selection of inputs, includir price assumptions, future operating and capital costs assumptions and tax rat jurisdiction, among others. Because of the complexity involved in estimating proved reserves, management also used an independent petroleum engineering consultin perform a review of the processes and controls used by the Company's internal res to determine estimates of proved oil and gas reserves.

Auditing the Company's DD&A calculation is complex because of the use the internal reservoir engineers and the independent petroleum engineering and the evaluation of management's determination of the inputs described al 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 oper effectiveness of the Company's internal controls over its processes to calculate DD&A, management's controls over the completeness and accuracy of the finan provided to the internal reservoir engineers for use in estimating proved oil and ga

Our audit procedures included, among others, evaluating the professiona and objectivity of the Company's internal reservoir engineers primarily respo overseeing the preparation of the proved oil and gas reserve estimates a independent petroleum engineering consulting firm used to review the Company's pro controls. In addition, in assessing whether we can use the work of the in engineers, we evaluated the completeness and accuracy of the financial described above used by the internal reservoir engineers in estimating p gas reserves by agreeing them to source documentation and we identified an corroborative and contrary evidence. We also tested the accuracy of the calculation, including comparing the proved oil and gas reserve amounts used in the the Company's reserve report.

Valuation and recognition of proved and unproved oil & gas prope in business combinations

Description of the Matter

During 2021, the Company closed its acquisition of Concho Resources In acquisition of Permian assets from Shell Enterprises LLC resulting in the recognition unproved oil and gas properties within net properties, plants and equipm billion and $8.6 billion, respectively. As described in Note 3, the transactions we for as business combinations under FASB ASC 805 using the acquisition metho requires assets acquired and liabilities assumed to be measured at their acquisitio values. Oil and gas properties were valued using a discounted cash flow approac market participant assumptions and third party valuation experts were engaged to prepare fair value estimates. Significant inputs to the valuation of provec oil and gas properties include estimates of future commodity price assumpt production profiles of reserve estimates, the pace of drilling plans, future operating discount rates using a market-based weighted average cost of capital.

Auditing the Company's accounting for its valuation of proved and unpro properties is complex and considerably judgmental due to the significant required by management of reserves and resources associated with the a and the sensitivity of significant assumptions used in determining the fair val evaluating the reasonableness of management's estimates and assumptions used, t procedures performed required a high degree of auditor judgment and a including involving internal specialists.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the oper effectiveness of the Company's internal controls over its process to estimate the fair va acquired proved and unproved oil and gas properties, including management's rev significant assumptions used as inputs to the fair value calculations and t the analysis.

To test the estimated fair value of the acquired proved and unproved oil
properties, our audit procedures included, among others, evaluating the significant a
used and testing the completeness and accuracy of the underlying data suppo
significant assumptions. For example, we compared certain significant assumptions
industry, third-party data and historical results for reasonableness. We also perfor
analyses of significant assumptions, to evaluate the extent of their impac
value calculation. In addition, we involved our valuation specialists to assist wi
significant assumptions included in the fair value estimate. Furthermore, we evalua
qualifications professionals and objectivity of the third party valuation specialist engag
Company to prepare the fair value of the acquired proved and unproved oil and ga

/s/ Ernst & Young LLP

We have served as ConocoPhillips’ auditor since 1949.

Houston, Texas
February 17, 2022

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 3 on criteria established in Internal Control – Integrated Framework issued by the Committee of Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our ConocoPhillips (the Company) maintained, in all material respects, effective internal control over financial December 31, 2021, based on the COSO criteria. As indicated under the heading "Assessm Control Over Financial Reporting" in the accompanying Reports of Management, management's ass conclusion on the effectiveness of internal control over financial reporting did not include th the assets acquired from Shell Enterprise LLC, which is included in the 2021 consolidated f ConocoPhillips and constituted approximately 10 percent of consolidated total assets as of 2021. Our audit of internal control over financial reporting of ConocoPhillips also did not include a the internal control over financial reporting of the assets acquired from Shell Enterprise LLC.

We also have audited, in accordance with the standards of the Public Company Accounting (United States) (PCAOB), the consolidated balance sheets of the Company as of December 2020, the consolidated income statement, consolidated statements of comprehensive income equity and cash flows for each of the three years in the period ended December 31, 2021, and the rel our report dated February 17, 2022, expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over f reporting and for its assessment of the effectiveness of internal control over financial reporting included heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Reports of Our responsibility is to express an opinion on the Company's internal control over financial repo our audit. We are a public accounting firm registered with the PCAOB and are required to be in respect to the Company in accordance with the U.S. federal securities laws and the applicable rules regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards r plan and perform the audit to obtain reasonable assurance about whether effective internal control reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, a risk that a material weakness exists, testing and evaluating the design and operating effectiveness of based on the assessed risk, and performing such other procedures as we considered necessary in 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 reaso
regarding the reliability of financial reporting and the preparation of financial statements fo
purposes in accordance with generally accepted accounting principles. A company's internal control ove
reporting includes those policies and procedures that (1) pertain to the maintenance of records that,
detail, accurately and fairly reflect the transactions and dispositions of the assets of the company,
reasonable assurance that transactions are recorded as necessary to permit preparation of financial st
accordance with generally accepted accounting principles, and that receipts and expenditures of the co
being made only in accordance with authorizations of management and directors of the company; and
reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or dis
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 preven
misstatements. Also, projections of any evaluation of effectiveness to future periods are su
that controls may become inadequate because of changes in conditions, or that the degree of c
the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2022

Consolidated Income Statement

Years Ended December 31		Millions of Dollars		
		2021	2020	2
Revenues and Other Income				
Sales and other operating revenues	**$**	**45,828**	18,784	32,
Equity in earnings of affiliates		**832**	432	7
Gain on dispositions		**486**	549	1,9
Other income (loss)		**1,203**	(509)	1,3
Total Revenues and Other Income		**48,349**	19,256	36,
Costs and Expenses				
Purchased commodities		**18,158**	8,078	11,
Production and operating expenses		**5,694**	4,344	5,3
Selling, general and administrative expenses		**719**	430	5
Exploration expenses		**344**	1,457	7
Depreciation, depletion and amortization		**7,208**	5,521	6,0
Impairments		**674**	813	4
Taxes other than income taxes		**1,634**	754	9
Accretion on discounted liabilities		**242**	252	3
Interest and debt expense		**884**	806	7
Foreign currency transaction (gains) losses		**(22)**	(72)	
Other expenses		**102**	13	
Total Costs and Expenses		**35,637**	22,396	27,
Income (loss) before income taxes		**12,712**	(3,140)	9,5
Income tax provision (benefit)		**4,633**	(485)	2,2
Net income (loss)		**8,079**	(2,655)	7,2
Less: net income attributable to noncontrolling interests		**-**	(46)	(
Net Income (Loss) Attributable to ConocoPhillips	**$**	**8,079**	(2,701)	7,1
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic	**$**	**6.09**	(2.51)	6
Diluted		**6.07**	(2.51)	6
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,324,194**	1,078,030	1,117
Diluted		**1,328,151**	1,078,030	1,123

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

ConocoPhillips

Years Ended December 31		Millions of Dollars		
		2021	2020	2
Net Income (Loss)	**$**	**8,079**	(2,655)	7,
Other comprehensive income (loss)				
Defined benefit plans				
Prior service credit arising during the period		**-**	29	
Reclassification adjustment for amortization of prior service credit included in net income (loss)		**(38)**	(32)	(
Net change		**(38)**	(3)	(
Net actuarial gain (loss) arising during the period		**357**	(210)	(
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)		**178**	117	1
Net change		**535**	(93)	
Nonsponsored plans*		**5**	1	
Income taxes on defined benefit plans		**(108)**	20	
Defined benefit plans, net of tax		**394**	(75)	
Unrealized holding gain (loss) on securities		**(2)**	2	
Reclassification adjustment for loss included in net income		**(1)**	-	
Income taxes on unrealized holding loss on securities		**1**	-	
Unrealized holding gain (loss) on securities, net of tax		**(2)**	2	
Foreign currency translation adjustments		**(124)**	209	6
Income taxes on foreign currency translation adjustments		**-**	3	
Foreign currency translation adjustments, net of tax		**(124)**	212	6
Other Comprehensive Income, Net of Tax		**268**	139	7
Comprehensive Income (Loss)		**8,347**	(2,516)	8,
Less: comprehensive income attributable to noncontrolling interests		**-**	(46)	(
Comprehensive Income (Loss) Attributable to ConocoPhillips	**$**	**8,347**	(2,562)	7,9

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

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **Co**

At December 31		Millions of Dollars	
		2021	2
Assets			
Cash and cash equivalents	$	**5,028**	2,
Short-term investments		**446**	3,
Accounts and notes receivable (net of allowance of $2 and $4, respectively)		**6,543**	2,
Accounts and notes receivable—related parties		**127**	1
Investment in Cenovus Energy		**1,117**	1,
Inventories		**1,208**	1,
Prepaid expenses and other current assets		**1,581**	4
Total Current Assets		**16,050**	12,
Investments and long-term receivables		**7,113**	8,
Loans and advances—related parties		**-**	1
Net properties, plants and equipment (net of accumulated DD&A of $64,735 and $62,213, respectively)		**64,911**	39,
Other assets		**2,587**	2,
Total Assets	$	**90,661**	62,
Liabilities			
Accounts payable	$	**5,002**	2,
Accounts payable—related parties		**23**	
Short-term debt		**1,200**	6
Accrued income and other taxes		**2,862**	3
Employee benefit obligations		**755**	6
Other accruals		**2,179**	1,
Total Current Liabilities		**12,021**	5,
Long-term debt		**18,734**	14,
Asset retirement obligations and accrued environmental costs		**5,754**	5,
Deferred income taxes		**6,179**	3,
Employee benefit obligations		**1,153**	1,
Other liabilities and deferred credits		**1,414**	1,
Total Liabilities		**45,255**	32,
Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2021—2,091,562,747 shares; 2020—1,798,844,267 shares)			
Par value		**21**	
Capital in excess of par		**60,581**	47,
Treasury stock (at cost: 2021—789,319,875 shares; 2020—730,802,089 shares)		**(50,920)**	(47,
Accumulated other comprehensive loss		**(4,950)**	(5,
Retained earnings		**40,674**	35,
Total Equity		**45,406**	29,
Total Liabilities and Equity	$	**90,661**	62,

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows
ConocoPhillips

Years Ended December 31		Millions of Dollars		
		2021	2020	20
Cash Flows From Operating Activities				
Net income (loss)	**$**	**8,079**	(2,655)	7,2
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization		**7,208**	5,521	6,0
Impairments		**674**	813	4
Dry hole costs and leasehold impairments		**44**	1,083	4
Accretion on discounted liabilities		**242**	252	3
Deferred taxes		**1,346**	(834)	(4
Undistributed equity earnings		**446**	645	5
Gain on dispositions		**(486)**	(549)	(1,9
(Gain) loss on CVE common shares		**(1,040)**	855	(6
Other		**(788)**	43	(3
Working capital adjustments				
Decrease (increase) in accounts and notes receivable		**(2,500)**	521	5
Increase in inventories		**(160)**	(25)	(
Decrease (increase) in prepaid expenses and other current assets		**(649)**	76	
Increase (decrease) in accounts payable		**1,399**	(249)	(3
Increase (decrease) in taxes and other accruals		**3,181**	(695)	(6
Net Cash Provided by Operating Activities		**16,996**	4,802	11,
Cash Flows From Investing Activities				
Capital expenditures and investments		**(5,324)**	(4,715)	(6,6
Working capital changes associated with investing activities		**134**	(155)	(1
Acquisition of businesses, net of cash acquired		**(8,290)**	-	
Proceeds from asset dispositions		**1,653**	1,317	3,0
Net sales (purchases) of investments		**3,091**	(658)	(2,9
Collection of advances/loans—related parties		**105**	116	1
Other		**87**	(26)	(1
Net Cash Used in Investing Activities		**(8,544)**	(4,121)	(6,6
Cash Flows From Financing Activities				
Issuance of debt		**-**	300	
Repayment of debt		**(505)**	(254)	(
Issuance of company common stock		**145**	(5)	(
Repurchase of company common stock		**(3,623)**	(892)	(3,5
Dividends paid		**(2,359)**	(1,831)	(1,5
Other		**7**	(26)	(1
Net Cash Used in Financing Activities		**(6,335)**	(2,708)	(5,2
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash		**(34)**	(20)	(
Net Change in Cash, Cash Equivalents and Restricted Cash		**2,083**	(2,047)	(7
Cash, cash equivalents and restricted cash at beginning of period		**3,315**	5,362	6,1
Cash, Cash Equivalents and Restricted Cash at End of Period	**$**	**5,398**	3,315	5,3

Restricted cash of $152 million and $28 million is included in the "Prepaid expenses and other current assets" and "Othe respectively, of our Consolidated Balance Sheet as of December 31, 2021.
Restricted cash of $94 million and $230 million is included in the "Prepaid expenses and other current assets" and "Othe respectively, of our Consolidated Balance Sheet as of December 31, 2020.
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	Contr Inte
Balances at December 31, 2018	$	18	46,879	(42,905)	(6,063)	34,010	
Net income						7,189	
Other comprehensive loss					746		
Dividends declared—ordinary ($1.34 per share of common stock)						(1,500)	
Repurchase of company common stock				(3,500)			
Distributions to noncontrolling interests and other							(
Distributed under benefit plans			104				
Changes in Accounting Principles*					(40)	40	
Other						3	
Balances at December 31, 2019	$	18	46,983	(46,405)	(5,357)	39,742	
Net income (loss)						(2,701)	
Other comprehensive income					139		
Dividends declared—ordinary ($1.69 per share of common stock)						(1,831)	
Repurchase of company common stock				(892)			
Distributions to noncontrolling interests and other							
Disposition							
Distributed under benefit plans			150				
Other						3	
Balances at December 31, 2020	$	18	47,133	(47,297)	(5,218)	35,213	
Net income						**8,079**	
Other comprehensive income					**268**		
Dividends declared							
Ordinary ($1.75 per share of common stock)						**(2,359)**	
Variable return of cash ($0.20 per share of common stock)						**(260)**	
Acquisition of Concho		**3**	**13,122**				
Repurchase of company common stock				**(3,623)**			
Distributed under benefit plans			**326**				
Other						**1**	
Balances at December 31, 2021	**$**	**21**	**60,581**	**(50,920)**	**(4,950)**	**40,674**	

**Cumulative effect of the adoption of ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Income."*

See Notes to Consolidated Financial Statements.

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, if applicable, 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, Middle East and North Africa; Asia Pacific; and Other International. See Note 23.

- **Foreign Currency Translation**—Adjustments resulting from the process of translating foreign 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 U.S. GAAP 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. We do not apply hedge accounting to our derivative instruments.

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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 6

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 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 SAGD facilities 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).
-

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.

- **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 (loss) on dispositions" line of our consolidated income statement. When partial 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). Fair value is estimated using a present value approach, incorporating assumptions about estimated amounts and timing of settlements and impacts of the use of technologies. *See Note 8*

  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 through a 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.

- **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. 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 and prices believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

- **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 ar 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 expen 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 commo 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 ye been issued as common stock, along with an adjustment to net income (loss) for dividend equivale paid on unvested unit awards that are considered participating securities. Diluted net income per sha of common stock includes unvested stock, unit or option awards granted under our compensation pla and vested but unexercised stock options, but only to the extent these instruments dilute net incor per share, primarily under the treasury-stock method. Diluted net loss per share, which is calculated th same as basic loss per share, does not assume conversion or exercise of securities that would hav an antidilutive effect. Treasury stock is excluded from the daily weighted-average number of common sha outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

Note 2—Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2021	2
Crude oil and natural gas	$	**647**	4
Materials and supplies		**561**	5
Total inventories	$	**1,208**	1,(
Inventories valued on the LIFO basis	$	**395**	2

The estimated excess of current replacement cost over LIFO cost of inventories was approximately $251 millior and $87 million at December 31, 2021 and 2020, respectively.

Note 3—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 of our consolidated income statement. All cash proceeds and payments are included i the "Cash Flows From Investing Activities" section of our consolidated statement of cash flows.

During the year, we completed the acquisitions of Concho Resources Inc. (Concho) and of Shell Enterprises LLC's (Shell) Permian assets. The acquisitions were accounted for as business combinations und FASB Topic ASC 805 using the acquisition method, which requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Fair value measurements were made for acquired assets and liabilities, and adjustments to those measurements may be made in subsequent periods, up to one year from the acquisition date as we identify new information about facts and circumstances that existed as of the acquisition date to consider.

2021

Acquisition of Concho Resources Inc.

In January 2021, we completed our acquisition of Concho, an independent oil and gas exploration and production company with operations across New Mexico and West Texas focused in the Permian Basin. Total consideration for the all-stock transaction was valued at $13.1 billion, in which 1.46 shares of ConocoPhillips common stock were exchanged for each outstanding share of Concho common stock.

Total Consideration

Number of shares of Concho common stock issued and outstanding (in thousands)*		194,
Number of shares of Concho stock awards outstanding (in thousands)*		1,5
Number of shares exchanged		195,
Exchange ratio		1
Additional shares of ConocoPhillips common stock issued as consideration (in thousands)		285,
Average price per share of ConocoPhillips common stock**	$	45.9
Total Consideration (Millions)	**$**	**13,**

**Outstanding as of January 15, 2021.*
***Based on the ConocoPhillips average stock price on January 15, 2021.*

Oil and gas properties were valued using a discounted cash flow approach incorporating internally generated price assumptions; production profiles; and operating and development cost assumptions. Debt assumed in the acquisition was valued based on observable market prices. The fair values determined for accounts receivable, accounts payable, and most other current assets and current liabilities were equivalent to the carrying value due to their short-term nature. The total consideration of $13.1 billion was allocated to the identifiable assets and liabilities based on their fair values as of January 15, 2021.

Assets Acquired	Millions of Dollars	
Cash and cash equivalents	$	3
Accounts receivable, net		7
Inventories		
Prepaid expenses and other current assets		
Investments and long-term receivables		3
Net properties, plants and equipment		18,
Other assets		
Total assets acquired	**$**	**20,**
Liabilities Assumed		
Accounts payable	$	6
Accrued income and other taxes		
Employee benefit obligations		
Other accruals		5
Long-term debt		4,(
Asset retirement obligations and accrued environmental costs		3
Deferred income taxes		1,(
Other liabilities and deferred credits		1
Total liabilities assumed	**$**	**7,**
Net assets acquired	**$**	**13,**

With the completion of the Concho transaction, we acquired proved and unproved properties of approximately $11.8 billion and $9 billion, respectively.

We recognized approximately $157 million of transaction-related costs, all of which were expense quarter of 2021. These non-recurring costs related primarily to fees paid to advisors and the settlement of share-based awards for certain Concho employees based on the terms of the Merger Agreement.

In the first quarter of 2021, we commenced a company-wide restructuring program, the scope of which included combining the operations of the two companies as well as other global restructuring activities. We recognized non-recurring restructuring costs mainly for employee severance and related incremental pension benefit costs.
The impact from these transaction and restructuring costs to the lines of our consolidated income statement for the year ended December 31, 2021, are below:

	Millions of Dollars		
	Transaction Cost	Restructuring Cost	Total Cost
Production and operating expenses	$	128	1
Selling, general and administration expenses	135	67	2
Exploration expenses	18	8	
Taxes other than income taxes	4	2	
Other expenses	-	29	
	$ 157	**234**	**3**

On February 8, 2021, we completed a debt exchange offer related to the debt assumed from Concho. As a result of the debt exchange, we recognized an additional income tax related restructuring charge of $75 million. *See Note 17.*

From the acquisition date through December 31, 2021, "Total Revenues and Other Income" and "Net Income (Loss) Attributable to ConocoPhillips" associated with the acquired Concho business were approximately $6,57 million and $233 million, respectively. The results associated with the Concho business for th same period include a before-and after-tax loss of $305 million and $233 million, respectively, on the acquired derivative contracts. The before-tax loss is recorded within "Total Revenues and Other Income" on ou consolidated income statement. *See Note 12.*

Acquisition of Shell Permian Assets
In December 2021, we completed our acquisition of Shell assets in the Permian based Delaware Basin. The accounting close date used for reporting purposes was December 31, 2021. Assets acquire included approximately 225,000 net acres and producing properties located entirely in Texas. Total consideration for the transaction was $8.7 billion.

Oil and gas properties were valued using a discounted cash flow approach incorporating internally generated and market participant price assumptions, production profiles, and operating and developmen cost assumptions. The fair values determined for accounts receivable, accounts payable, and most other curre assets and current liabilities were equivalent to the carrying value due to their short-term nature. The total $8.7 billion consideration was allocated to the identifiable assets and liabilities based on their fair values at th acquisition date.

Assets Acquired		Millions of Dollars
Accounts receivable, net	$	3
Inventories		
Net properties, plants and equipment		8,(
Other assets		
Total assets acquired	**$**	**9,(**

Liabilities Assumed		
Accounts payable	$	2
Accrued income and other taxes		
Other accruals		
Asset retirement obligations and accrued environmental costs		
Other liabilities and deferred credits		
Total liabilities assumed	**$**	**3**
Net assets acquired	**$**	**8,(**

With the completion of the Shell Permian transaction, we acquired proved and unproved properties of approximately $4.2 billion and $4.4 billion, respectively. We recognized approximately $4 million of transaction-related costs which were expensed during 2021.

Supplemental Pro Forma (unaudited)
The following tables summarize the unaudited supplemental pro forma financial informatio for the years ended December 31, 2021, and 2020, as if we had completed the acquisitions of Concho and the Shell Permian assets on January 1, 2020.

	Millions of Dollars				
	Year Ended December 31, 2021				
		As reported		Pro forma Shell	Pro forma Combi
Total Revenues and Other Income	$	48,349		3,220	51,
Income (loss) before income taxes		12,712		1,201	13,
Net Income (Loss) attributable to ConocoPhillips		8,079		920	8,9
Earnings per share:					
Basic net loss	$	6.09			6
Diluted net loss		6.07			6

	Millions of Dollars				
	Year Ended December 31, 2020				
		As reported	Pro forma Concho	Pro forma Shell	Pro forma Comb
Total Revenues and Other Income	$	19,256	3,762	1,685	24,
Income (loss) before income taxes		(3,140)	787	(247)	(2,6
Net Income (Loss) attributable to ConocoPhillips		(2,701)	498	(189)	(2,3
Earnings per share:					
Basic net loss	$	(2.51)			(1
Diluted net loss		(2.51)			(1

The unaudited supplemental pro forma financial information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the transactio been completed on January 1, 2020, nor is it necessarily indicative of future operating results of the combined entity. The unaudited pro forma financial information for the twelve-month period ending December 31, 2020 is a result of combining the consolidated income statement of ConocoPhillips with the results of Concho and the Shell Permian assets acquired from Shell. The pro forma results do not include transaction-related costs, nor any cost savings anticipated as a result of the transactions. The pro forma results include adjustments from Concho's historical result to remove impairment expense of $10.5 billion and $1.9 billion related to oil and gas properties and goodwill, respectively. Other adjustments made relate primarily to DD&A, which is based on the unit-of-productio method, resulting from the purchase price allocated to properties, plants and equipment. We believe the estimates and assumptions are reasonable, and the relative effects of the transaction are properly reflected.

Announced Acquisitions

In December 2021, we announced that we have notified Origin Energy that we are exercisi our preemption right to purchase an additional 10 percent shareholding interest in APLNG from Origin Energy for $1.645 billion, wh will be funded from cash on the balance sheet, before customary adjustments. The effectiv date of the transaction will be July 1, 2020 with closing anticipated to occur in the first quarter of 2022 subject to Australian government approvals. See *Note 4* and *Note 7*.

Assets Sold

In 2020, we completed the sale of our Australia-West asset and operations. The sales agreement entitled us to a $200 million payment upon a final investment decision (FID) of the Barossa development project. On March 30, 2021, FID was announced, and as such, we recognized a $200 million gain on disposition in the first qua of 2021. The purchaser failed to pay the FID bonus when due. We have commenced an arbitration proceeding against the purchaser to enforce our contractual right to the $200 million, plus interest accruing from the due da Results of operations related to this transaction are reflected in our Asia Pacific segment. *See Note 11*.

In January 2022, we entered into an agreement to sell our interests in certain noncore assets in the Lower 48 segment for $440 million before customary adjustments. This transaction is expected to close in the second quarter of 2022.

2020

Asset Acquisition

In August 2020, we completed the acquisition of additional Montney acreage in Canada fro Kelt Exploration Ltd. for $382 million after customary adjustments, plus the assumption of $31 million in financing obligations associated with partially owned infrastructure. This acquisition consisted primarily of undeveloped properties and included 140,000 net acres in the liquids-rich Inga Fireweed asset Montney zone, which is dire adjacent to our existing Montney position. The transaction increased our Montney acreage position to 295,00 approximately with a 100 percent working interest. This agreement was accounted for as an asset acquisition resulting in the recognition of $419 million of PP&E, $7 million of ARO and accrued environmental costs, and $31 million financing obligations recorded primarily to long-term debt. Results of operations for the Montney asset are reported in our Canada segment.

Assets Sold

In February 2020, we sold our Waddell Ranch interests in the Permian Basin for $184 million after customar adjustments. No gain or loss was recognized on the sale. Results of operations for the Wadde Ranch interests sold were reported in our Lower 48 segment.

In March 2020, we completed the sale of our Niobrara interests for approximately $359 million after custom adjustments and recognized a before-tax loss on disposition of $38 million. At the time of disposition, ou interest in Niobrara had a net carrying value of $397 million, consisting primarily of $433 million of PP&E and $34 millio ARO. The before-tax losses associated with our interests in Niobrara, including the loss on disposition noted above and impairment of $386 million recorded when we signed an agreement to sell our interests i the fourth quarter of 2019, were $25 million and $372 million for the years ended December 31, 2020 and 20 respectively. Results of operations for the Niobrara interests sold were reported in our Lower 48 segmen

In May 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations, and based on an effective date of January 1, 2019, we received proceeds of $765 million. We recognized a before-tax gain of $587 million related to this transaction in 2020. At the time of disposition, the net carrying value of the subsidiaries sold was approximately $0.2 billion, excluding $0.5 billion of cash. The net carrying value consisted primarily of $1.3 billion of PP&E and $0.1 billion of other current assets offset by $0.7 billion of ARO, $0.3 billion deferred tax liabilities, and $0.2 billion of other liabilities. The before-tax earnings associated with the subsidiaries sold, including the gain on disposition noted above, were $851 million and $372 million for the years ende December 31, 2020 and 2019, respectively. Production from the beginning of the year through the disposition date in May 2020 averaged 43 MBOED. The sales agreement entitled us to an additional $200 million upon F the Barossa development project. Results of operations for the subsidiaries sold were reported in our Asia Pacific segment.

2019

Assets Sold

In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in the Golde 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 sold were reported in our Lower 48 segment.

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 2018. On September 30, 2019, we completed the sale for proceeds of $2.2 billion and recognized a $1.7 billion before-t 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 $0.9 billion, consisting primarily of $1.6 billion of PP&E, $0.5 billion of cumulative foreign 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, including the gain on disposition noted above, was $2.1 billion for the year ended December 31, 2019. Results of operations for the U.K. were reported within our Europe, Middle East 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 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 segment.

In the fourth quarter of 2019, we sold our interests in the Magnolia field and platform for $16 million of proceeds and recognized a before-tax gain of $83 million. At the time of sale, the net carrying value consisted of $ million of PP&E offset by $70 million of ARO. The Magnolia results of operations were reported within our Lower 48 segment.

Note 4—Investments, Loans and Long-Term Receivables

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

	Millions of Dollar		
		2021	2
Equity investments	**$**	**6,701**	7,5
Loans and advances—related parties		**-**	1
Long-term receivables		**98**	1
Long-term investments in debt securities		**248**	2
Other investments		**66**	
	$	**7,113**	8,

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2021, 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 process and export LNG.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliate QatarEnergy (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent)—produces and liquefies natura 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			
		2021	2020	2
Revenues	**$**	**11,824**	7,931	11,
Income before income taxes		**3,946**	1,843	3,
Net income		**2,557**	1,426	3,

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

	Millions of Dollar	
	2021	2
Current assets	$ **4,493**	2,5
Noncurrent assets	**36,602**	35,
Current liabilities	**3,498**	2,1
Noncurrent liabilities	**17,465**	18,

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, 2021, retained earnings included $42 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,279 million, $1,076 million and $1,378 million in 2021, 2020 and 2019, respectively.

APLNG

APLNG is a joint venture focused on producing CBM from the Bowen and Surat basins in Queensland, Australia. Natural gas is sold to domestic customers and LNG is processed and exported to Asia Pacific markets. 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. All amounts were drawn from the facility. APLNG achieved financial completion on its original $8.5 billion project finance facility during the third quarter of 2017, resulting in the facility being nonrecourse. The project finance facility has been refinanced over time and at December 31, 2021, this facility was composed of a financing agreement with the Export-Import Bank of the United States, a commercial bank facility and two United States Private Placem note facilities. APLNG made its first principal and interest repayment in March 2017 and is scheduled to make bi-annual payments until September 2030. At December 31, 2021, a balance of $5.7 billion was outstanding on the facilities. *See Note 10*.

During the fourth quarter of 2021, Origin Energy Limited agreed to the sale of 10 percent of their interest in APLNG for $1.645 billion, before customary adjustments. ConocoPhillips announced in December 20 that we were exercising our preemption right under the APLNG Shareholders Agreement to purchase an additional 10 percent shareholding interest in APLNG, subject to government approvals. The sales price associated with this preemption right was determined to reflect a relevant observable market participant view of APLNG's fa value which was below the carrying value of our existing investment in APLNG. Based on a review of the fac and circumstances surrounding this decline in fair value, we concluded in the fourth quarter of 2021 the impairment was other than temporary under the guidance of FASB ASC Topic 323, and the recognition of an impairme of our existing investment was necessary. Accordingly, we recorded a noncash, $688 million before-tax and after-tax impairment in the fourth quarter of 2021. The impairment, which is included in the "Impairments" line on our consolidated income statement, had the effect of reducing the carrying value of our existing investment to $5,574 million at December 31, 2021. This carrying value is included in the "Investments and long-term receivables" line on our consolidated balance sheet. *See Note 7*.

The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $5,523 million, resulting in a basis difference of $51 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 valu basis to individual production license areas owned by APLNG. Any future additional payments are expected to be allocated in a similar manner. 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 2021, 2020 and 2019 was after-tax expense of $39 million, $41 million and $36 million, respectively, representing the amortization of this basis difference on currently producing licenses.

QG3

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. W provided project financing, with a current outstanding balance of $114 million as described below under “Loans.” At December 31, 2021, the book value of our equity method investment in QG3, excluding the project financing, was $736 millio We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliate 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 LN Terminal and Golden Pass Pipeline, but we sold those interests in the second quarter of 20 while retaining the basic use agreements. See Note 3 Currently, the LNG from QG3 is being sold to markets outside of the U.S.

Loans

As part of our normal ongoing business operations and consistent with industry practice, w enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans to certain affiliated and non-affiliated companies.

At December 31, 2021, significant loans to affiliated companies include $114 million in project financing to QG3, which is recorded within the “Accounts and notes receivable—related parties” line on our consolidated balance sheet. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans fro 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 commercia bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities becan nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through Jul 2022.

Note 5—Investment in Cenovus Energy

Our investment in Cenovus Energy (CVE) common shares is carried on our balance sheet at fair value.

	December 31		
		2021	20
Number of shares of CVE common stock (millions)		**91**	2
Ownership of issued and outstanding common stock		**4.5%**	1(
Closing price on NYSE on last trading day ($/share)	**$**	**12.28**	6.
Fair Value (millions of dollars)	**$**	**1,117**	1,2

During 2021, we began to dispose of CVE shares, selling 117 million shares during the year, recognizing proceeds of $1.18 billion, $1.14 billion of which was received during the year. Proceeds related to the sale of our CVE shares are presented within “Cash Flows from Investing Activities” on our consolidated statement cash flows. Subject to market conditions, we intend to continue to decrease our investment.

All gains and losses are recognized within “Other income (loss)” on our consolidated income statement. See Note 13

		Millions of Dollars		
		2021	2020	2
Total Net gain (loss) on equity securities	$	**1,040**	(855)	
Less: Net gain (loss) on equity securities sold during the period		**473**		
Unrealized gain (loss) on equity securities still held at the reporting date	$	**567**	(855)	

Note 6—Suspended Wells and Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 202
2020 and 2019:

		Millions of Dollars		
		2021	2020	2
Beginning balance at January 1	$	**682**	1,020	8
Additions pending the determination of proved reserves		**10**	164	2
Reclassifications to proved properties		**-**	(42)	(
Sales of suspended wells		**-**	(313)	(
Charged to dry hole expense		**(32)**	(147)	(
Ending balance at December 31	$	**660**	682	1,(

**Includes $3 million of assets held for sale in Australia-West at December 31, 2019.*
For additional details on suspended wells charged to dry hole expense, see the Exploration Expenses section of this Note.

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

		Millions of Dollars		
		2021	2020	2
Exploratory well costs capitalized for a period of one year or less	$	**4**	156	2
Exploratory well costs capitalized for a period greater than one year		**656**	526	8
Ending balance	$	**660**	682	1,(

**Includes $3 million of assets held for sale in Australia-West at December 31, 2019.*

Number of projects with exploratory well costs capitalized for a period greater than one year	**22**	22	

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, 2021:

		Millions of Dollars			
			Suspended Since		
		Total	2018-2020	2015-2017	2004-
Willow—Alaska[1]		313	262	51	
Surmont—Canada[1]		121	2	19	1
PL 1009—Norway[1]		43	43	-	
PL 891—Norway[1]		34	34	-	
Narwhal Trend—Alaska[1]		25	25	-	
WL4-00—Malaysia[1]		24	24	-	
PL782S—Norway[1]		22	22	-	
NC 98—Libya[2]		13	-	-	
Other of $10 million or less each[1][2]		61	21	11	
Total	$	656	433	81	1

(1)Additional appraisal wells planned.

(2)Appraisal drilling complete; costs being incurred to assess development.

Exploration Expenses

The charges discussed below are included in the "Exploration expenses" line on our consolidated income statement.

2020

In our Alaska segment, we recorded a before-tax impairment of $828 million for the entire associated carrying value of capitalized undeveloped leasehold costs related to our Alaska North Slope Gas ass
We no longer believe the project will advance, and there is no current market for the asset.

In our Other International segment, our interests in the Middle Magdalena Basin of Colomb
are in force majeure. As we have no immediate plans to perform under existing contracts; therefore, in 2020, we
expensed a before-tax $84 million for dry hole costs of a previously suspended well and an impairme
of the associated capitalized undeveloped leasehold carrying value.

In our Asia Pacific segment, we recorded before-tax expense of $50 million related to dry hole costs of a previously suspended well and an impairment of the associated capitalized undeveloped leasehold carrying value associated with the Kamunsu East Field in Malaysia that is no longer in our development plans.

2019

In our Lower 48 segment, we recorded a before-tax impairment of $141 million for the associated carryin
capitalized undeveloped leasehold costs and dry hole expenses of $11 million before-tax due to our decision to discontinue exploration activities related to our Central Louisiana Austin Chalk acreage.

Note 7—Impairments

During 2021, 2020 and 2019, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2021	2020	2
Alaska	**$ 5**	-	
Lower 48	**(8)**	804	4
Canada	**6**	3	
Europe, Middle East and North Africa	**(24)**	6	
Asia Pacific	**695**	-	
	$ 674	813	4

2021

We recorded an impairment of $688 million on our APLNG investment included within the Asia Pac segment. See *Note 4* and *Note 13*.

In our Lower 48 segment, we recorded a credit to impairment of $89 million due to a decreased ARO estimate for a previously sold asset, in which we retained the ARO liability. This was offset by recorded impairments of $84 million during the fourth quarter of 2021, related to certain noncore assets due to changes development plans. See *Note 13*.

In our Europe, Middle East and North Africa segment, we recorded a credit to impairment of $24 million due decreased ARO estimates on fields in Norway which ceased production and were fully depreciated in prior years.

2020

We recorded impairments of $813 million, primarily related to certain noncore assets in the Lowe significant decrease in the outlook for current and long-term natural gas prices in early 202 48. Due to a we recorded impairments of $523 million, primarily for the Wind River Basin operations area, consisting of developed properties in the Madden Field and the Lost Cabin Gas Plant, in the first quarter of 2020. Additionally, due primarily to changes in development plans solidified in the last quarter of 2020, we recognized additional impairments of $287 million in the Lower 48 during the fourth quarter. See *Note 13*.

2019

In the Lower 48, we recorded impairments of $402 million, primarily related to developed properties Niobrara asset which were written down to our fair value less costs to sell. See *Note 3*.

Note 8—Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Doll	
	2021	2
Asset retirement obligations	**$ 5,926**	5,5
Accrued environmental costs	**187**	1
Total asset retirement obligations and accrued environmental costs	**6,113**	5,7
Asset retirement obligations and accrued environmental costs due within one year*	**(359)**	(3
Long-term asset retirement obligations and accrued environmental costs	**$ 5,754**	5,4

**Classified as a current liability on the balance sheet under "Other accruals."*

Asset Retirement Obligations

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

We have numerous AROs we are required to perform under law or contract once an asset i 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 ga platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2021 and 2020, our overall ARO changed as follows:

		Millions of Doll
	2021	2
Balance at January 1	**$ 5,573**	6,
Accretion of discount	**238**	2
New obligations	**555**	2
Changes in estimates of existing obligations	**(113)**	(3
Spending on existing obligations	**(164)**	(1
Property dispositions	**(108)**	(7
Foreign currency translation	**(55)**	
Balance at December 31	**$ 5,926**	5,

Accrued Environmental Costs

Total accrued environmental costs at December 31, 2021 and 2020, were $187 million and $180 million, respectively.

We had accrued environmental costs of $135 million and $116 million at December 31, 2021 and 2020 respectively, related to remediation activities in the U.S. and Canada. We had also accrued in Corporate and Other $36 million and $48 million of environmental costs associated with sites no longer in operation 2021 and 2020, respectively. In addition, $16 million included at both December 31, 2021 and 2020, 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 $109 million at December 31, 2021. The total expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are $153 million.

Note 9—Debt

Long-term debt at December 31 was:

		Millions of Dollar	
		2021	2
9.125% Debentures due 2021	**$**	**-**	1
2.4% Notes due 2022		**329**	3
7.65% Debentures due 2023		**78**	
3.35% Notes due 2024		**426**	4
8.2% Debentures due 2025		**134**	1
3.35% Notes due 2025		**199**	1
6.875% Debentures due 2026		**67**	
4.95% Notes due 2026		**1,250**	1,
7.8% Debentures due 2027		**203**	2
3.75% Notes due 2027		**981**	
3.75% Notes due 2027		**19**	
4.3% Notes due 2028		**973**	
4.3% Notes due 2028		**27**	
7.375% Debentures due 2029		**92**	
7% Debentures due 2029		**200**	2
6.95% Notes due 2029		**1,549**	1,
8.125% Notes due 2030		**390**	3
2.4% Notes due 2031		**489**	
2.4% Notes due 2031		**11**	
7.2% Notes due 2031		**575**	5
7.25% Notes due 2031		**500**	5
7.4% Notes due 2031		**500**	5
5.9% Notes due 2032		**505**	5
4.15% Notes due 2034		**246**	2
5.95% Notes due 2036		**500**	5
5.951% Notes due 2037		**645**	6
5.9% Notes due 2038		**600**	6
6.5% Notes due 2039		**2,750**	2,
4.3% Notes due 2044		**750**	7
5.95% Notes due 2046		**500**	5
7.9% Debentures due 2047		**60**	
4.875% Notes due 2047		**800**	
4.85% Notes due 2048		**590**	
4.85% Notes due 2048		**10**	
Floating rate notes due 2022 at 1.02% – 1.12% during 2021 and 1.12% – 2.81% during 2020		**500**	5
Marine Terminal Revenue Refunding Bonds due 2031 at 0.04% – 0.15% during 2021 and 0.1% – 7.5% during 2020		**265**	2
Industrial Development Bonds due 2035 at 0.01% – 0.12% during 2021 and 0.11% – 7.5% during 2020		**18**	
Commercial Paper at 0.05% – 0.22% during 2021		**-**	3
Other		**35**	
Debt at face value		**17,766**	14,
Finance leases		**1,261**	8
Net unamortized premiums, discounts and debt issuance costs		**907**	1
Total debt		**19,934**	15,
Short-term debt		**(1,200)**	(6
Long-term debt	**$**	**18,734**	14,

Note 10—Guarantees

At December 31, 2021, 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, 2021, 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 2021 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 to be 9 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, 2021, 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. The final guarantee expires in the fourth quarter of 2041. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $660 million ($1.2 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 15 to 24 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $180 million and would become payable if APLNG does not perform. At December 31, 2021, the carrying value of these guarantees was approximately $11 million.

See Note 11

Other Guarantees for

Note 11—Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of busines 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 vario 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 w the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimat and no amount within the range is a better estimate than any other amount, then the low end of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. We accrue receivables for insurance or other third-party recoveries when applicable. 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 certa See Note 17.

Note 8,

Litigation and Other Contingencies

We are subject to various lawsuits and claims including but not limited to matters involving 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, claims of alleged environmental contamination and damages from historic operations, and climate change. 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 adequa of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

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 throughp capacity not utilized. In addition, at December 31, 2021, we had performance obligations secured by letters of credit of $337 million (issued as direct bank letters of credit) related to various purchase commitments fo 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 respon 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 expropriat 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. 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, which automatically stayed enforcement of the award. On September 29, 2021, the ICSID annulment committee lifted the stay of enforcement of the award. The annulme proceedings have been suspended as a result of Venezuela's non-payment of advances to cover the costs of these proceedings.

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 pe 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. 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 has failed to cure its breach. As a result, ConocoPhillips has resumed legal enforcement actions. To date, ConocoPhillips has receive approximately $76 million in connection with the ICC award. ConocoPhillips has ensured that the settlement a any actions taken to enforce it meet all appropriate U.S. regulatory requirements, including those related to any applicable sanctions imposed by the U.S. against Venezuela.

Note 12—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer nee capture market opportunities, and manage foreign exchange currency risk.

Commodity Derivative Instruments

Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and NG

Commodity 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, 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 and certain gas contracts. We do not apply 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	
		2021	2
Assets			
Prepaid expenses and other current assets	$	**1,168**	2
Other assets		**75**	
Liabilities			
Other accruals		**1,160**	2
Other liabilities and deferred credits		**63**	

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

		Millions of Dollars		
		2021	2020	2
Sales and other operating revenues	$	**(228)**	19	1
Other income (loss)		**25**	4	
Purchased commodities		**75**	11	(1

On January 15, 2021, we assumed financial derivative instruments consisting of oil and natural gas swaps in connection with the acquisition of Concho. At the acquisition date, the financial derivative instruments acquired were recognized at fair value as a net liability of $456 million with settlement dates under the contrac through December 31, 2022. During 2021, we recognized a loss on settlement of these contracts of $305 million. This loss associated with the acquired financial instruments is recorded within the "Sales and other operating revenues" line on our consolidated income statement. In connection with the settlement, we issued a cash payment of $761 million during 2021. Cash settlements related to the derivative contracts are presented wit "Cash Flows From Operating Activities" on our consolidated statement of cash flows.

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

	Open Position Long/(Short)	
	2021	2
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**4**	(
Basis	**(22)**	(

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.

Our foreign currency exchange derivative instruments are held at fair value on our consolidated balance sheet. Related cash flows are included within operating activities on our consolidated statement of cash flows. 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	
	2021	20
Assets		
Prepaid expenses and other current assets	**$ 28**	
Liabilities		
Other accruals	**9**	1

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

	Millions of Dollars		
	2021	2020	2
Foreign currency transaction (gains) losses	**$ (5)**	(40)	

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

		In Millions Notional Currency	
		2021	2
Foreign Currency Exchange Derivatives			
Buy British pound, sell euro	GBP	**155**	
Sell British pound, buy euro	GBP	**-**	
Sell Canadian dollar, buy U.S. dollar	CAD	**-**	3
Buy Canadian dollar, sell U.S. dollar	CAD	**77**	
Buy Australian dollar, sell U.S. dollar	AUD	**1,850**	

At December 31, 2021, we had outstanding foreign currency exchange forward contracts t
to buy $1.5 billion AUD at $0.71 AUD against the U.S. dollar in anticipation of our future acquisition of an additional
interest in APLNG. At December 31, 2020, we had outstanding foreign currency exchange forward contracts to s
$0.458 billion CAD at $0.775 CAD against the U.S. dollar

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

- Time deposits: Interest bearing deposits placed with financial institutions for a predetermined amount of time.
- 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.
- Foreign government obligations: Securities issued by foreign governments.
- 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 and the table reflects remaining maturities at December 31, 2021 and 2020:

	Millions of Dollars				
	Carrying Amount				
	Cash and Cash Equivalents		Short-Term Investments		Investments a Long-Term Receiva
	2021	2020	**2021**	2020	**2021**
Cash	**$ 670**	597			
Demand Deposits	**1,554**	1,133			
Time Deposits					
1 to 90 days	**2,363**	1,225	**217**	2,859	
91 to 180 days			**4**	448	
Within one year			**4**	13	
One year through five years					**-**
U.S. Government Obligations					
1 to 90 days	**431**	23	**-**	-	
	$ 5,018	2,978	**225**	3,320	**-**

The following investments in debt securities classified as available for sale are carried at fa value in the consolidated balance sheet at December 31, 2021 and 2020:

		Millions of Dollars				
		Carrying Amount				
		Cash and Cash Equivalents		Short-Term Investments		Investments a Long-Term Receiva
		2021	2020	**2021**	2020	**2021**
Major Security Type						
Corporate Bonds	**$**	**3**	-	**128**	130	**173**
Commercial Paper		**7**	13	**82**	155	
U.S. Government Obligations		**-**	-	**-**	4	**2**
U.S. Government Agency Obligations				**2**	-	**8**
Foreign Government Obligations				**7**	-	**2**
Asset-backed Securities				**2**	-	**63**
	$	**10**	13	**221**	289	**248**

Cash and Cash Equivalents and Short-Term Investments have remaining maturities within year. Investments and Long-Term Receivables have remaining maturities that vary from greater than one year through eight years.

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

		Millions of Dollars			
		Amortized Cost Basis		Fair Value	
		2021	2020	**2021**	2
Major Security Type					
Corporate Bonds	**$**	**305**	271	**304**	2
Commercial Paper		**88**	168	**89**	1
U.S. Government Obligations		**2**	17	**2**	
U.S. Government Agency Obligations		**10**	17	**10**	
Foreign Government Obligations		**9**	2	**9**	
Asset-Backed Securities		**65**	41	**65**	
	$	**479**	516	**479**	5

As of December 31, 2021 and 2020, total unrealized losses for debt securities classified as available for sale were negligible. Additionally, as of December 31, 2021 and 2020, investments i these debt securities in an unrealized loss position for which an allowance for credit losses has not been recorded were negligible.

For the years ended December 31, 2021 and 2020, proceeds from sales and redemptions c investments in debt securities classified as available for sale were $594 million and $412 million, respectively. Gross realized gains and losses included in earnings from those sales and redemptions 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 o 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, U.S. government and government agency obligations, time deposits with major international banks and financial institutions, high-quality corporate bonds, foreign government obligations and asset-backed securities. Our long-term investments in debt securities are placed in high-quality corporat bonds, asset-backed securities, U.S. government and government agency obligations, foreign government obligations, and time deposits with major international banks and financial institutions.

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 receivab 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 may require collateral to limit the exposure to l including, letters of credit, prepayments and surety bonds, as well as 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 amount 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 perm 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 continge features that were in a liability position on December 31, 2021 and December 31, 2020, was $18 million and $25 million, respectively. For these instruments, no collateral was posted as of December 31, 2021 or December 31, 2020. If our credit rating had been downgraded below investment grade on December 31, 2021, we would ha been required to post $52 million of additional collateral, either with cash or letters of credit.

Note 13—Fair Value Measurement

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

The classification of an asset or liability is based on the lowest level of input significant to i 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. There were no material transfers into or out of Level 3 during 2021 or 2020.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include o investment in CVE common 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 CVE, which is valued using quotes for shares on the NYSE, and ou 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 forw purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers o pricing service companies that are all corroborated by market data. Level 2 also includes our investme in debt securities classified as available for sale including investments in corporate bonds, commercial pa asset-backed securities, U.S. government agency obligations and foreign government obligations tha 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 historic 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, 2021				December 31, 2020			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	T
Assets								
Investment in Cenovus Energy	**$ 1,117**	**-**	**-**	**1,117**	1,256	-	-	1,
Investments in debt securities	**2**	**477**	**-**	**479**	17	501	-	5
Commodity derivatives	**562**	**619**	**62**	**1,243**	142	101	12	2
Total assets	**$ 1,681**	**1,096**	**62**	**2,839**	1,415	602	12	2,
Liabilities								
Commodity derivatives	**$ 593**	**543**	**87**	**1,223**	120	91	9	2
Total liabilities	**$ 593**	**543**	**87**	**1,223**	120	91	9	2

The following table summarizes those commodity derivative balances subject to the right o 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	N Amou
December 31, 2021								
Assets	**$**	**1,243**	**85**	**1,158**	**650**	**508**	**-**	**50**
Liabilities		**1,223**	**82**	**1,141**	**650**	**491**	**36**	**45**
December 31, 2020								
Assets	$	255	2	253	157	96	10	8
Liabilities		220	1	219	157	62	4	5

At December 31, 2021 and December 31, 2020, 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	L
Year ended December 31, 2021							
Net PP&E (held for use)							
December 31, 2021	**$**	**472**	**-**	**-**	**472**		
Equity Method Investments							
December 31, 2021		**5,574**	-	**5,574**	-		**6**
Year ended December 31, 2020							
Net PP&E (held for use)							
March 31, 2020	$	65	-	-	65		5
December 31, 2020		268	-	-	268		2

Net PP&E (held for use)

During 2021 and 2020, the estimated fair value of certain noncore assets included in our Lower 48 segment declined to amounts below the carrying values. The carrying values were written down to fair values. The fair values were estimated based on internal discounted cash flow models using the following estimated future production, an outlook of future prices from a combination of exchanges (short-term) and pricing service companies and our internal outlook (long-term), future operating costs and capital expenditures, and a discount rate believed to be consistent with those used by principal market participants. The arithmetic average of significant unobservable inputs used in the Level 3 fair value measurements were as follows:

December 31, 2021	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Inputs	Range (Arithmetic Average)
Lower 48 Gulf Coast and Rockies noncore field	$ 472	Discounted cash flow	Commodity production (MBOED)	0.2 - 17
			Commodity price outlook* ($/BOE)	$41.45 - $93.68
			Discount rate**	7.3% - 9.7%

*Commodity price outlook based on a combination of external pricing service companies' and our internal outlook for years 2022-2050; future prices escalated at 2.0% annually after year 2050.
**Determined as the weighted average cost of capital of a group of peer companies, adjusted for risks where appropriate.

March 31, 2020	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Inputs	Range (Arithmetic Average)
Wind River Basin	$ 65	Discounted cash flow	Natural gas production (MMCFD)	8.4 - 55.2
			Natural gas price outlook* ($/MMBTU)	$2.67 - $9.17
			Discount rate**	7.9% - 9.1%

*Henry Hub natural gas price outlook based on a combination of external pricing service companies' outlooks for years 2022-20… future prices escalated at … annually after year 2034.
**Determined as the weighted average cost of capital of a group of peer companies, adjusted for risks where appropriate.

December 31, 2020	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Inputs	Range (Arithmetic Average)
Central Basin Platform	$ 244	Discounted cash flow	Commodity production (MBOED)	0.5 - 12.7
			Commodity price outlook* ($/BOE)	$37.35 - $1…
			Discount rate**	6.8% - 7.7%

*Commodity price outlook based on a combination of external pricing service companies' and our internal outlook for years 2021-2050; future prices escalated at 2.0% annually after year 2050.
**Determined as the weighted average cost of capital of a group of peer companies, adjusted for risks where appropriate.

Equity Method Investments

During the fourth quarter of 2021, Origin Energy Limited agreed to the sale of 10 percent of their interest in APLNG for $1.645 billion, before customary adjustments. ConocoPhillips announced in December 20… that we were exercising our preemption right under the APLNG Shareholders Agreement to purchase an additional 10 percent shareholding interest in APLNG, subject to government approvals. The sales price associat… with this preemption right was determined to reflect a relevant observable market participant view of APLNG's fa… value which was below the carrying value of our existing investment in APLNG. As such, our investment in APLNG was written down to its fair value of $5,574 million, resulting in a before-tax charge of $688 million. See Note 4 and Note 7.

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 repor 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 carryi amount reported on the balance sheet approximates fair value. The valuation technique and methods us 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: *See Note 5* for a discussion of the carrying value and fair valu of our investment in CVE common 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 12.*
- 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 a is categorized as Level 2 in the fair value hierarchy. *See Note 4.*
- 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 valu
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using price available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.
- Commercial paper: The carrying amount of our commercial paper instruments approximates fair value and is reported on the balance sheet as short-term debt.

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	
	2021	2020	**2021**	2
Financial assets				
Investment in CVE common shares	$ **1,117**	1,256	**1,117**	1,
Commodity derivatives	**593**	88	**593**	
Investments in debt securities	**479**	518	**479**	5
Loans and advances—related parties	**114**	220	**114**	2
Financial liabilities				
Total debt, excluding finance leases	**18,673**	14,478	**22,451**	19,
Commodity derivatives	**537**	59	**537**	

<u>Commodity Derivatives</u>

At December 31, 2021, commodity derivative assets and liabilities are presented net with no obligation to return cash collateral and $36 million of rights to reclaim cash collateral, respectively. At December 31, 2020, commodity derivative assets and liabilities are presented net with $10 million in obligations to return cash collater and $4 million of rights to reclaim cash collateral, respectively.

Note 14—Equity

Common Stock

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

	Shares		
	2021	2020	2
Issued			
Beginning of year	**1,798,844,267**	1,795,652,203	1,791,637
Acquisition of Concho	**285,928,872**	-	
Distributed under benefit plans	**6,789,608**	3,192,064	4,014
End of year	**2,091,562,747**	1,798,844,267	1,795,652
Held in Treasury			
Beginning of year	**730,802,089**	710,783,814	653,288
Repurchase of common stock	**58,517,786**	20,018,275	57,495
End of year	**789,319,875**	730,802,089	710,783

Preferred Stock

We have authorized 500 million shares of preferred stock, par value $0.01 per share, none of which was issu or outstanding at December 31, 2021 or 2020.

Noncontrolling Interests

In the second quarter of 2020, we completed the divestiture of our subsidiaries that held o Australia-West assets and operations. These assets included the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures in which there was a noncontrolling interest. As a result, as of December 31, 2021 and 2020, we ha no noncontrolling interests.

Repurchase of Common Stock

In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. In May 2021, we began a paced monetization of our CV common shares, the proceeds of which have been applied to share repurchases. Share repurchases since inception totaled 247 million shares at a cost of $14 billion through the end of December 2021.

Note 15—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 t 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 ha executed lease agreements that require it to guarantee the residual value of certain leased office buildings. For additional information about guarantees, see *Note 10*. 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. We adopted the provisions of FASB ASU No. 2016-02, "Leases" (ASC Topic 842) and its amendments, beginning January 1, 2019. This ASU superseded the requirements in FASB ASC Topic 840, "Leases" (ASC Topic 840). 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 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 against us as the operator and there is no separate arrangement to sublease the underlying leased asset to our co-venturers, 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 co-venturers for their share of the lease cost as the underlying leased asset is utilized in joint venture activities. As a result, lease costs are presented in our consolidated income statement and statement of cash flows on a proportional basis. If we are a nonoperating co-venturer, we recognize a right-of-use asset and corresponding lease liability only if we are the 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. 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.

The following table summarizes the right-of-use assets and lease liabilities for both the operating and finance leases on our consolidated balance sheet as of December 31:

		Millions of Dollars			
		2021		2020	
		Operating Leases	Finance Leases	Operating Leases	Finan Lease
Right-of-Use Assets					
Properties, plants and equipment					
Gross	$		**1,812**		1,3
Accumulated DD&A			**(857)**		(7
Net PP&E*			**955**		6
Prepaid expenses and other current assets	$	**16**	**2**		
Other assets		**649**		783	
Lease Liabilities					
Short-term debt**	$		**280**		1
Other accruals		**188**		226	
Long-term debt***			**981**		7
Other liabilities and deferred credits		**479**		559	
Total lease liabilities	$	**667**	**1,261**	785	8

* Includes proportionately consolidated finance lease assets of $208 million at December 31, 2021 and $258 million at December 31
** Includes proportionately consolidated finance lease liabilities of $154 million at December 31, 2021 and $92 million at December 3
*** Includes proportionately consolidated finance lease liabilities of $462 million at December 31, 2021 and $120 million at December
2020.

The following table summarizes our lease costs:

		Millions of Dollars		
		2021	2020	2
Lease Cost*				
Operating lease cost	$	**278**	321	
Finance lease cost				
Amortization of right-of-use assets		**148**	163	
Interest on lease liabilities		**27**	34	
Short-term lease cost**		**21**	42	
Total lease cost***	$	**474**	560	

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

The following table summarizes the lease terms and discount rates as of December 31:

	2021	2
Lease Term and Discount Rate		
Weighted-average term (years)		
Operating leases	**5.97**	6
Finance leases	**7.49**	7
Weighted-average discount rate (percent)		
Operating leases	**2.66**	2
Finance leases	**3.24**	4

The following table summarizes other lease information:

	Millions of Dollars		
	2021	2020	20
Other Information*			
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ **204**	232	2
Operating cash flows from finance leases	**6**	11	
Financing cash flows from finance leases	**73**	255	
Right-of-use assets obtained in exchange for operating lease liabilities	$ **174**	250	4
Right-of-use assets obtained in exchange for finance lease liabilities	**447**	426	

*The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas co-venturers. 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, 2021:

	Millions of Dollars	
	Operating Leases	Fina Lea
Maturity of Lease Liabilities		
2022	$ 195	3
2023	143	1
2024	114	1
2025	68	1
2026	50	1
Remaining years	159	4
Total*	729	1,4
Less: portion representing imputed interest	(62)	(1
Total lease liabilities	$ 667	1,2

*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 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 oil and gas venture.

Note 16—Employee Benefit Plans

Pension and Postretirement Plans

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

		Millions of Dollars					
		Pension Benefits				Other Benef	
		2021		2020		**2021**	2
		U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation							
Benefit obligation at January 1	**$**	**2,548**	**4,403**	2,319	3,880	**170**	2
Service cost		**73**	**61**	85	54	**2**	
Interest cost		**53**	**79**	66	85	**4**	
Plan participant contributions		**-**	**-**	-	1	**16**	
Plan amendments		**-**	**-**	-	2	**-**	(
Actuarial (gain) loss		**(117)**	**(176)**	319	398	**(16)**	
Benefits paid		**(654)**	**(162)**	(241)	(151)	**(40)**	(
Curtailment		**12**	**-**	-	2	**1**	
Recognition of termination benefits		**9**	**-**	-	3	**-**	
Foreign currency exchange rate change		**-**	**(81)**	-	129	**-**	
Benefit obligation at December 31*	**$**	**1,924**	**4,124**	2,548	4,403	**137**	1
**Accumulated benefit obligation portion of above at December 31:*	*$*	***1,793***	***3,658***	*2,359*	*4,095*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	**$**	**1,770**	**4,793**	1,591	4,306	**-**	
Actual return on plan assets		**97**	**147**	321	416	**-**	
Company contributions		**451**	**119**	99	60	**24**	
Plan participant contributions		**-**	**1**	-	1	**16**	
Benefits paid		**(654)**	**(162)**	(241)	(151)	**(40)**	(
Foreign currency exchange rate change		**-**	**(86)**	-	161	**-**	
Fair value of plan assets at December 31	**$**	**1,664**	**4,812**	1,770	4,793	**-**	
Funded Status	**$**	**(260)**	**688**	(778)	390	**(137)**	(1

		Millions of Dollars					
		Pension Benefits				Other Bene	
		2021		2020		**2021**	2
		U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31							
Noncurrent assets	**$**	**1**	**991**	-	746	**-**	
Current liabilities		**(29)**	**(15)**	(56)	(11)	**(34)**	(
Noncurrent liabilities		**(232)**	**(288)**	(722)	(345)	**(103)**	(1
Total recognized	**$**	**(260)**	**688**	(778)	390	**(137)**	(1
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31							
Discount rate		**2.80%**	**2.15**	2.30	1.80	**2.65**	2
Rate of compensation increase		**4.00**	**3.40**	4.00	3.10		
Interest crediting rate for applicable benefits		**2.50**		2.10			
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31							
Discount rate		**2.60%**	**1.80**	3.05	2.35	**2.35**	3
Expected return on plan assets		**5.20**	**2.50**	5.80	3.60		
Rate of compensation increase		**4.00**	**3.40**	4.00	3.35		
Interest crediting rate for applicable benefits		**2.10**		4.10			

For both U.S. and international pension plans, the overall expected long-term rate of retur 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 rat of return for each class of assets.

During 2021, the actuarial gains related to the benefit obligations for U.S. and internationa plans were primarily related to an increase in the discount rates. During 2020 and 2019, the actuarial losses related to the benefit obligations for the U.S. and international plans were primarily related to a decrease in the discount rates.

The following tables summarize information related to the Company's pension plans with projected and accumulated benefit obligations in excess of the fair value of the plans' assets:

		Millions of Dollars			
		Pension Benefits			
		2021		2020	
		U.S.	**Int'l.**	U.S.	I
Pension Plans with Projected Benefit Obligation in Excess of Plan Assets					
Projected benefit obligation	**$**	**261**	**362**	2,548	3
Fair value of plan assets		**-**	**58**	1,770	
Pension Plans with Accumulated Benefit Obligation in Excess of Plan Assets					
Accumulated benefit obligation	**$**	**234**	**271**	2,359	3
Fair value of plan assets		**-**	**9**	1,770	

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:

		Millions of Dollars					
		Pension Benefits				Other Bene	
		2021		2020		**2021**	2
		U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial loss (gain)	**$**	**188**	**86**	467	326	**(1)**	
Unrecognized prior service cost (credit)		**-**	**1**	-	-	**(145)**	(1

		Millions of Dollars					
		Pension Benefits				Other Bene	
		2021		2020		**2021**	2
		U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)							
Net gain (loss) arising during the period	**$**	**134**	**207**	(83)	(120)	**16**	
Amortization of actuarial loss included in income (loss)*		**145**	**33**	95	21	**-**	
Net change during the period	**$**	**279**	**240**	12	(99)	**16**	
Prior service credit (cost) arising during the period	**$**	**-**	**-**	-	(1)	**-**	
Amortization of prior service (credit) included in income (loss)		**-**	**(1)**	-	(1)	**(37)**	(
Net change during the period	**$**	**-**	**(1)**	-	(2)	**(37)**	

**Includes settlement (gains) losses recognized in 2021 and 2020.*

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		
	2021		2020		2019		**2021**	2020	2
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 73**	**61**	85	54	79	69	**2**	2	
Interest cost	**53**	**79**	66	85	79	97	**4**	6	
Expected return on plan assets	**(80)**	**(120)**	(85)	(145)	(74)	(138)	**-**	-	
Amortization of prior service credit	**-**	**(1)**	-	(1)	-	(2)	**(37)**	(31)	(
Recognized net actuarial loss (gain)	**43**	**33**	51	22	54	32	**-**	1	
Settlements loss (gain)	**102**	**-**	44	(1)	62	-	**-**	-	
Curtailment loss	**12**	**-**	-	-	-	-	**-**	-	
Net periodic benefit cost	**$ 203**	**52**	161	14	200	58	**(31)**	(22)	(

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

We recognized pension settlement losses of $102 million in 2021, $43 million in 2020, and $62 million in 2019 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

In determining net pension and other postretirement benefit costs, we amortize prior servi cost 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 non-pension postretirement benefit plans for health and life insurance. T health care plans are contributory and subject to various cost sharing features, with participant and compan contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-6 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 6.5 percent in 2022 that declines to 5 percent by 2028. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.25 percent in 2022 that increases to 5 percent by 2028.

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 th investment program from time to time. The target allocations for plan assets are 22 percent equity securities, 74 percent debt securities, 3 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, 2021 and 2020.

- Fair values of equity securities and government debt securities categorized in Level 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 an government debt securities categorized in Level 2 are estimated using recently executed transactions and market price quotations 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 i 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 securitie are categorized in Level 3 of the fair value hierarchy.
- Fair values of investments in common/collective trusts are determined by the issue 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 c 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 prici models with market input parameters from third-party sources.
- Fair values of insurance contracts are valued at the present value of the future bene 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 insurar 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, 2021, the participating interest in the annuity contract was valued at $83 million and consisted of $206 million in debt securities, less $123 million for the accumulated benefit obligation covered by the contract. At December 31, 2020, the participating interest in the annuity contract was valued at $94 million and consisted of $233 million in debt securities, less $139 million for the accumulated benefit obligation covered by the contract. 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 contra

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	T
2021									
Equity securities									
U.S.	$	**3**	**-**	**5**	**8**	**-**	**-**	**-**	
International		**42**	**-**	**-**	**42**	**-**	**-**	**-**	
Mutual funds		**17**	**-**	**-**	**17**	**236**	**403**	**-**	**6**
Debt securities									
Corporate		**-**	**1**	**-**	**1**	**-**	**-**	**-**	
Mutual funds		**-**	**-**	**-**	**-**	**511**	**-**	**-**	**5**
Cash and cash equivalents		**-**	**-**	**-**	**-**	**68**	**-**	**-**	
Real estate		**-**	**-**	**-**	**-**	**-**	**-**	**157**	**1**
Total in fair value hierarchy	$	**62**	**1**	**5**	**68**	**815**	**403**	**157**	**1,**
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$				**394**				**4**
Debt securities									
Common/collective trusts					**1,073**				**3,**
Cash and cash equivalents					**9**				
Real estate					**36**				
Total**	$	**62**	**1**	**5**	**1,580**	**815**	**403**	**157**	**4,**

*In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are 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 amount presented in the Change in Fair Value of Plan Assets.

**Excludes the participating interest in the insurance annuity contract with a net asset of $83 million and net receivables related to transactions of $5 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	T
2020								
Equity securities								
U.S.	$ -	3	5	8	-	-	-	
International	99	-	-	99	-	-	-	
Mutual funds	72	-	-	72	235	384	-	6
Debt securities								
Corporate	-	1	-	1	-	-	-	
Mutual funds	-	-	-	-	455	-	-	4
Cash and cash equivalents	-	-	-	-	74	-	-	
Derivatives	-	-	-	-	6	-	-	
Real estate	-	-	-	-	-	-	142	1
Total in fair value hierarchy	$ 171	4	5	180	770	384	142	1,
Investments measured at net asset value*								
Equity securities								
Common/collective trusts	$			678				3
Debt securities								
Common/collective trusts				730				3,
Cash and cash equivalents				8				
Real estate				79				1
Total**	$ 171	4	5	1,675	770	384	142	4,

*In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are 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 amount presented in the Change in Fair Value of Plan Assets.

**Excludes the participating interest in the insurance annuity contract with a net asset of $94 million and net receivables related to transactions of $7 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 2022, we expect to contribute approximately $115 millio to our domestic qualified and nonqualified pension and postretirement benefit plans and $80 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		Othe Benef
		U.S.	Int'l.	
2022	$	369	152	
2023		185	152	
2024		176	158	
2025		154	162	
2026		144	164	
2027–2031		557	893	

The following table summarizes our severance accrual activity:

		Millions of Dollars		
		2021	2020	2
Balance at January 1	$	**24**	23	
Accruals		**170**	14	
Benefit payments		**(116)**	(13)	(
Balance at December 31	**$**	**78**	24	

Accruals include severance costs associated with our company-wide restructuring program. Of the remaining balance at December 31, 2021, $ 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 17 investment 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 2019, new employees, rehires, and employees that elected to opt out of Title II of the ConocoPhillips Retirement Plan are eligible to receive a Company Retirement Contribution (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 $93 million in 2021, $62 million in 2020, and $82 million in 2019.

We have several defined contribution plans for our international employees, each with its o terms and eligibility depending on location. Total compensation expense recognized for these international plan was approximately $26 million in 2021, $25 million in 2020, and $30 million in 2019.

Share-Based Compensation Plans

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 net income and the associated tax benefits (follows) were:

	Millions of Dollars		
	2021	2020	2
Compensation cost	$ **304**	159	2
Tax benefit	**76**	40	

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 for 2018 and 2019 awards and stock-settled beginning with 2020 awards.

The following summarizes our stock option activity for the year ended December 31, 2021

	Options	Weighted-Average Exercise Price	Millions of Dollars Aggre Intrinsic Value
Outstanding at December 31, 2020	16,922,525	$ 55.12	$
Exercised	**(3,846,361)**	**51.40**	
Expired or cancelled	**(1,102,381)**	**53.47**	
Outstanding at December 31, 2021	**11,973,783**	**$ 56.46**	**$**
Vested at December 31, 2021	**11,973,783**	**$ 56.46**	**$**
Exercisable at December 31, 2021	**11,973,783**	**$ 56.46**	**$**

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 shares of 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 cash payment of a dividend equivalent or an accrued reinvested 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, 2021:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2020	6,431,985	$ 58.94	
Granted	**4,590,103**	**46.56**	
Forfeited	**(566,047)**	**48.59**	
Issued	**(2,810,730)**	**54.74**	**$ 1**
Outstanding at December 31, 2021	**7,645,311**	**$ 53.81**	
Not Vested at December 31, 2021	**5,509,133**	**53.81**	

At December 31, 2021, the remaining unrecognized compensation cost from the unvested stock-settled units was $126 million, which will be recognized over a weighted-average period of 1.67 years, the longest period 2. years. The weighted-average grant date fair value of stock unit awards granted during 2020 was $57 and 2019 was $70.17, respectively. The total fair value of stock units issued during 2020 and 2019 was $143 million and $225 million, respectively.

Cash-Settled

Cash settled executive restricted stock units granted in 2018 and 2019 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, these 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 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. Beginning with executive restricted stock units granted in 2020 awards will be settled in stock.

The following summarizes our cash-settled stock unit activity for the year ended Decembe
31, 2021:

	Stock Units	Weighted-Average Grant Date Fair Value		Millions of Dollars Total Fair Value
Outstanding at December 31, 2020	614,615	$	39.95	
Granted	**11,186**		**57.19**	
Forfeited	**(2,927)**		**51.43**	
Issued	**(396,398)**		**50.75**	**$ 2**
Outstanding at December 31, 2021	**226,476**	**$**	**72.18**	
Not Vested at December 31, 2021	**59,443**		**72.18**	

At December 31, 2021, there was no remaining unrecognized compensation cost to be recorded fo
cash-settled units. The weighted-average grant date fair value of stock unit awards grante
during 2020 and 2019 were $41.52 and $68.20, respectively. The total fair value of stock units issued during 2020 an
2019 were negligible and $6 million, respectively.

Performance Share Program —Under the Plan, we also annually grant restricted performance sh
units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant c
(the performance period). Compensation expense is initially measured using the average fair market value o
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 t
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's separation 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 unti
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 effective grant date, for employees eligible for retirement by or shortly a
the grant date, we recognize compensation expense over the period beginning on the date of authorization ar
ending on the grant date. 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 c
the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stoc
per unit.
The following summarizes our stock-settled Performance Share Program activity for the ye
ended December 31, 2021:

	Stock Units	Weighted-Average Grant Date Fair Value		Millions of Dollars Total Fair Value
Outstanding at December 31, 2020	1,736,728	$	50.56	
Issued	**(287,881)**		**49.91**	**$**
Outstanding at December 31, 2021	**1,448,847**	**$**	**50.69**	
Not Vested at December 31, 2021	**3,191**	**$**	**48.61**	

At December 31, 2021, there was no remaining unrecognized compensation cost to be recorded on stock-settled performance shares. The weighted-average grant date fair value of stock-set PSUs granted during 2020 and 2019 was $58.61 and $58.90, respectively. The total fair value of stock-settled PSU issued during 2020 and 2019 was $13 million and $25 million, respectively.

Cash-Settled

In connection with and immediately following the separation of our Downstream businesse in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these P 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 th grant date, we recognize compensation expense over the period beginning on the date of authorization ar 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 th 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 settlemen 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 periods 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 yea Ended December 31, 2021:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2020	124,529	$ 39.95	
Granted	**1,073,228**	**46.65**	
Settled	**(1,080,078)**	**48.13**	**$**
Outstanding at December 31, 2021	**117,679**	**$ 72.18**	

At December 31, 2021, all outstanding cash-settled performance awards were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of cash-settled PSUs granted during 2020 and 2019 was $58.61 and $58.90, respectively. The total fair value of cash-settled performance share awards settled during 2020 and 2019 was $[illegible] million and $17 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, as part of an executive compensation program that has been discontinued or acquired as a result of an acquisition. Generally, the recipients of the restricted shares or units receive a dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2021:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2020	970,099	$ 47.78	
Granted	**797,704**	**46.43**	
Cancelled	**(1,948)**	**27.80**	
Issued	**(149,488)**	**46.80**	**$**
Outstanding at December 31, 2021	**1,616,367**	**$ 47.24**	
Not Vested at December 31, 2021	**695,958**	**$ 45.87**	

At December 31, 2021, the remaining compensation cost from the unvested restricted stock was $20 million, which will be recognized over a weighted-average period of 1.46 years, the longest period being 2 years. The weighted-average grant date fair value of awards granted during 2020 and 2019 was $51.46 and $63.58, respectively. The total fair value of awards issued during 2020 and 2019 was $6 million and $1 million, respectively.

Note 17—Income Taxes

Components of income tax provision (benefit) were:

	Millions of Dollars	
	2021	2020
Income Taxes		
Federal		
Current	**$ 32**	3
Deferred	**1,161**	(625)
Foreign		
Current	**3,128**	350
Deferred	**66**	(70)
State and local		
Current	**127**	(4)
Deferred	**119**	(139)
Total tax provision (benefit)	**$ 4,633**	(485)

Deferred income taxes reflect the net tax effect of temporary differences between the carr amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purpose Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars
	2021
Deferred Tax Liabilities	
PP&E and intangibles	**$ 10,170**
Inventory	**44**
Other	**213**
Total deferred tax liabilities	**10,427**
Deferred Tax Assets	
Benefit plan accruals	**321**
Asset retirement obligations and accrued environmental costs	**2,297**
Investments in joint ventures	**1,684**
Other financial accruals and deferrals	**827**
Loss and credit carryforwards	**7,402**
Other	**399**
Total deferred tax assets	**12,930**
Less: valuation allowance	**(8,342)**
Total deferred tax assets net of valuation allowance	**4,588**
Net deferred tax liabilities	**$ 5,839**

At December 31, 2021, noncurrent assets and liabilities included deferred taxes of $340 million and $179 respectively. At December 31, 2020, noncurrent assets and liabilities included deferred 363 million of $3,747 million, respectively.

At December 31, 2021, the loss and credit carryforward deferred tax assets were primarily related to U.S. foreign tax credit carryforwards of $5.5 billion and various jurisdictions net operating loss and credit 1 billion. If not utilized, U.S. foreign tax credits and net operating losses will begin to expire 2022.

Our overall deferred tax liability increased during 2021 by $1.2 billion due to our Concho acquisition. See Note

The following table shows a reconciliation of the beginning and ending deferred tax asset valuation allowance for 2021, 2020 and 2019:

		Millions of Dollars		
		2021	2020	2
Balance at January 1	**$**	**9,965**	10,214	
Charged to expense (benefit)		**(45)**	460	
Other*		**(1,578)**	(709)	
Balance at December 31	**$**	**8,342**	9,965	

**Represents changes due to originating deferred tax asset that have no impact to our effective tax rate, acquisitions/dispositions/revisions and the effect of translating foreign financial statements.*

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. At December 31, 2021, we have maintained a valuation allowance with respect to substantially all U.S. foreign tax credit carryforwards as well as certain net operating loss carryforwards for various jurisdictions. During 2021, the valuation allowance movement charged to earnings primarily relates to the fair value measurement of our CVE common shares that are not expected to be realized, and the expected realization of U.S. tax attributes associated with our planned disposition of our Indonesia assets. This is partially offset by Australian tax benefits associated with our impairment of APLNG that we do not expect to be realized. Other movements are primarily related to valuation allowances on expiring tax attributes. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects the net deferred tax assets, net of valuation allowances, will primarily be realized as offsets to reversing deferred tax liabilities. For more information on our pending Indonesia disposition, see Note 3.

During 2020, the valuation allowance movement charged to earnings primarily related to capital losses in Australia and to the fair value measurement of our CVE common shares that are not expected to be realized. Other movements are primarily related to valuation allowances on expiring tax attributes.

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 $105 million of 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, 2021, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,384 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 $219 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2021, 2020 and 2019.

		Millions of Dollars		
		2021	2020	2
Balance at January 1	**$**	**1,206**	1,177	1,0
Additions based on tax positions related to the current year		**15**	6	
Additions for tax positions of prior years		**177**	67	1
Reductions for tax positions of prior years		**(5)**	(34)	(
Settlements		**-**	(9)	
Lapse of statute		**(48)**	(1)	
Balance at December 31	**$**	**1,345**	1,206	1,1

Included in the balance of unrecognized tax benefits for 2021, 2020 and 2019 were $1,261 million, $1,138 millio and $1,100 million, respectively, which, if recognized, would impact our effective tax rate. Th balance of the unrecognized tax benefits increased in 2021 mainly due to U.S. tax credits acquired throug our acquisition of Concho. The balance of the unrecognized tax benefits increased in 2019 mainly due to the treatment of our PDVSA settlement. *See Note 3* and *Note 11*.

At December 31, 2021, 2020 and 2019, accrued liabilities for interest and penalties totaled $47 million, $46 millio and $42 million, respectively, net of accrued income taxes. Interest and penalties resulted in reduction to earnings of $1 million in 2021, a reduction of $4 million in 2020, and benefit to earnings of $3 million in 2019

We file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictio Audits in major jurisdictions are generally complete as follows: Canada (2016), U.S. (2017) and Norway (2020). 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. Within the next twelve months, we may ha audit periods close that could significantly impact our total unrecognized tax benefits. It is reasonably possibl such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

In January 2022, the IRS closed the 2017 audit of our U.S. federal income tax return. As a result, in the first quarter of 2022, we will recognize a previously unrecognized $475 million federal tax benefit related to the recovery of outside tax basis previously offset by a full reserve.

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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)	
		2021	2020	2019	**2021**	2020
Income (loss) before income taxes						
United States	**$**	**8,024**	(3,587)	4,704	**63.1 %**	114.2
Foreign		**4,688**	447	4,820	**36.9**	(14.2)
	$	**12,712**	(3,140)	9,524	**100.0 %**	100.0
Federal statutory income tax	**$**	**2,670**	(659)	2,000	**21.0 %**	21.0
Non-U.S. effective tax rates		**1,915**	194	1,399	**15.1**	(6.2)
Tax impact of debt restructuring		**75**	-	-	**0.6**	-
Australia disposition		**-**	(349)	-	**-**	11.1
U.K. disposition		**-**	-	(732)	**-**	-
Recovery of outside basis		**(55)**	(22)	(77)	**(0.4)**	0.7
Adjustment to tax reserves		**(11)**	18	9	**(0.1)**	(0.6)
Adjustment to valuation allowance		**(45)**	460	(225)	**(0.4)**	(14.6)
State income tax		**194**	(112)	123	**1.5**	3.6
Malaysia Deepwater Incentive		**-**	-	(164)	**-**	-
Enhanced oil recovery credit		**(99)**	(6)	(27)	**(0.8)**	0.2
Other		**(11)**	(9)	(39)	**(0.1)**	0.3
Total	**$**	**4,633**	(485)	2,267	**36.4 %**	15.5

Our effective tax rate for 2021 was driven by our jurisdictional tax rates for this profit mix with net favorable impacts from routine tax credits and valuation allowance adjustments. The valuation allowance adjustments primarily related to the fair value measurement and disposition of our CVE common shares of $218 million and the ability to utilize the U.S. foreign tax credit and capital loss carryforward due to our anticipated disposition of our Indonesia entities of $29 million. This was partially offset by an increase to our valuation allowa tax impact of the impairment related to our APLNG investment of $206 million for which we do not expect to receive a tax benefit.

Our effective tax rate for 2020 was impacted by the disposition of our Australia-West asset as well as the valuation allowance related to the fair value measurement of our CVE common shares. The Australia-West disposition generated a before-tax gain of $587 million with an associated tax benefit of $101 million and the de-recognition of deferred tax assets resulting in $92 million of tax expense. The disposition also generated an Australia capital loss tax benefit of $313 million which has been fully offset by a valuation allowanc Due to changes in the fair market value of CVE common shares, the valuation allowance was increased by $178 million to offset the expected capital loss.

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 ta asset fully offset with a valuation allowance. *See Note 3.*

During 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.

Note 18—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 Gain/(Loss) on Securities	Foreign Currency Translation	Accumul– Oth– Comprehe– Lo–
December 31, 2018	$ (361)	-	(5,702)	(6,0–
Other comprehensive income (loss)	51	-	695	74–
Cumulative effect of adopting ASU No. 2018-02*	(40)	-	-	(4–
December 31, 2019	(350)	-	(5,007)	(5,3–
Other comprehensive income	(75)	2	212	13–
December 31, 2020	(425)	2	(4,795)	(5,2–
Other comprehensive income (loss)	**394**	**(2)**	**(124)**	**26–**
December 31, 2021	**$ (31)**	**-**	**(4,919)**	**(4,9–**

*We adopted ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income," beginning January 1, 2019.

During 2019, we recognized $483 million of foreign currency translation adjustments related to th– completion of our sale of two ConocoPhillips U.K. subsidiaries. *See Note 3*.

The following table summarizes reclassifications out of accumulated other comprehensive l– during the years ended December 31:

	Millions of Dollars	
	2021	2–
Defined Benefit Plans	**$ 109**	
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	***$ 31***	

See Note 16.

Note 19—Cash Flow Information

		Millions of Dollars		
		2021	2020	2
Noncash Investing Activities				
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	**$**	**442**	(116)	2
Cash Payments				
Interest	**$**	**924**	785	8
Income taxes		**856**	905	2,9
Net Sales (Purchases) of Investments				
Short-term investments purchased	**$**	**(5,554)**	(12,435)	(4,9
Short-term investments sold		**8,810**	12,015	2,1
Investments and long-term receivables purchased		**(279)**	(325)	(1
Investments and long-term receivables sold		**114**	87	
	$	**3,091**	(658)	(2,9

The following items are included in the "Cash Flows from Operating Activities" section of ou consolidated cash flows:

In 2021, we made a total of $297 million in contributions to our U.S. qualified pension plan. In 20 we made a $324 million contribution to our U.K. pension plan.

We collected $330 million in 2019 from PDVSA under settlement agreements related to an aw issued by the ICC Tribunal in 2018. For more information on these settlements, see *Note 11*

See *Note 3* and *Note 12* for additional information on cash and non-cash changes to our consolidated balance sheet associated with our Concho acquisition.

Note 20—Other Financial Information

		Millions of Dollars		
		2021	2020	2
Interest and Debt Expense				
Incurred				
Debt	$	**887**	788	7
Other		**59**	73	
		946	861	8
Capitalized		**(62)**	(55)	(
Expensed	$	**884**	806	7
Other Income (Loss)				
Interest income	$	**33**	100	1
Gain (loss) on investment in Cenovus Energy*		**1,040**	(855)	6
Other, net		**130**	246	5
	$	**1,203**	(509)	1,

**See Note 5.*

Research and Development Expenditures—expensed	$	**62**	75	
Shipping and Handling Costs	$	**1,047**	857	1,(
Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**-**	-	
Lower 48		**-**	-	
Canada		**(1)**	(7)	
Europe, Middle East and North Africa		**(11)**	(15)	
Asia Pacific		**2**	(11)	
Other International		**1**	2	
Corporate and Other		**(7)**	(31)	
	$	**(16)**	(62)	

		Millions of Dollar	
		2021	2
Properties, Plants and Equipment			
Proved properties*	$	**114,274****	94,
Unproved properties*		**10,993**	4,
Other		**4,379**	3,
Gross properties, plants and equipment		**129,646**	102,
Less: Accumulated depreciation, depletion and amortization		**(64,735)****	(62,
Net properties, plants and equipment	$	**64,911**	39,

**Proved and Unproved properties increased by $20.0 billion and $6.9 billion, respectively, in 2021 compared with 2020, primar due to the Concho and Shell Permian acquisitions.*

***Excludes assets classified as held for sale at December 31, 2021. See Note 3.*

Note 21—Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employees. For disclosures on trusts for the benefit of employees, see Note 16.

Significant transactions with our equity affiliates were:

		Millions of Dollars		
		2021	2020	2
Operating revenues and other income	$	**88**	79	
Purchases		**5**	-	
Operating expenses and selling, general and administrative expenses		**196**	63	
Net interest income*		**(2)**	(5)	(

*We paid interest to, or received interest from, various affiliates. See Note 4, for additional information on loans affiliated companies.

Note 22—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		
		2021	2020	2
Revenue from contracts with customers	$	**34,590**	13,662	26,
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative		**11,500**	5,177	6,
Financial derivative contracts		**(262)**	(55)	(
Consolidated sales and other operating revenues	$	**45,828**	18,784	32,

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 is provided in conjunction with *Note 23—Segment Disclosures and Related Information*:

		Millions of Dollars		
		2021	2020	2
Revenue from Outside the Scope of ASC Topic 606 by Segment				
Lower 48	$	**9,050**	3,966	4,
Canada		**1,457**	727	6
Europe, Middle East and North Africa		**993**	484	8
Physical contracts meeting the definition of a derivative	$	**11,500**	5,177	6,

		Millions of Dollars		
		2021	2020	2
Revenue from Outside the Scope of ASC Topic 606 by Product				
Crude oil	$	**757**	395	8
Natural gas		**10,034**	4,339	5,
Other		**709**	443	4
Physical contracts meeting the definition of a derivative	$	**11,500**	5,177	6,

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 o the end of the reporting period.

Receivables and Contract Liabilities

Receivables from Contracts with Customers

At December 31, 2021, the "Accounts and notes receivable" line on our consolidated balan sheet includes trade receivables of $1,268 million compared with $1,827 million at December 31, 2020, 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) or 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 unde 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 whe NPNS has been elected.

Contract Liabilities from Contracts with Customers

We have entered into contractual arrangements where we license proprietary technology t 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 utili 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, 2020	$
Contractual payments received	
Revenue recognized	(
At December 31, 2021	$

Amounts Recognized in the Consolidated Balance Sheet at December 31, 2021	
Current liabilities	$

We expect to recognize the contract liabilities as of December 31, 2021, as revenue during 2022.

Note 23—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NG on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International.

Corporate and Other represents income and 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*. Intersegment sales are at prices that approximate market.

In 2021, we completed our acquisition of Concho, an independent oil and gas exploration and production company with operations across New Mexico and West Texas as well as our acquisition of Shell's Permian assets in the Delaware Basin. The accounting close date of the Shell transaction, used for reporting purposes, was December 31, 2021. Results of operations for Concho and assets acquired from Shell are included in our Lower 48 segment. Certain transaction and restructuring costs associated with these acquisitions are included in our Corporate and Other segment. See *Note 3*.

Analysis of Results by Operating Segment

	Millions of Dollars	
	2021	2020
Sales and Other Operating Revenues		
Alaska	$ **5,480**	3,408
Intersegment eliminations	**-**	(11)
Alaska	**5,480**	3,397
Lower 48	**29,306**	9,872
Intersegment eliminations	**(12)**	(51)
Lower 48	**29,294**	9,821
Canada	**4,077**	1,666
Intersegment eliminations	**(1,583)**	(405)
Canada	**2,494**	1,261
Europe, Middle East and North Africa	**5,902**	1,919
Intersegment eliminations	**-**	(2)
Europe, Middle East and North Africa	**5,902**	1,917
Asia Pacific	**2,579**	2,363
Other International	**4**	7
Corporate and Other	**75**	18
Consolidated sales and other operating revenues	$ **45,828**	18,784

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		
		2021	2020	2
Depreciation, Depletion, Amortization and Impairments				
Alaska	**$**	**1,002**	996	8
Lower 48		**4,067**	3,358	3,
Canada		**392**	342	2
Europe, Middle East and North Africa		**862**	775	8
Asia Pacific		**1,483**	809	1,
Other International		**-**	-	
Corporate and Other		**76**	54	
Consolidated depreciation, depletion, amortization and impairments	**$**	**7,882**	6,334	6,
Equity in Earnings of Affiliates				
Alaska	**$**	**5**	(7)	
Lower 48		**(18)**	(11)	(1
Canada		**-**	-	
Europe, Middle East and North Africa		**502**	311	4
Asia Pacific		**343**	137	4
Other International		**-**	2	
Corporate and Other		**-**	-	
Consolidated equity in earnings of affiliates	**$**	**832**	432	7
Income Tax Provision (Benefit)				
Alaska	**$**	**402**	(256)	4
Lower 48		**1,390**	(378)	1
Canada		**150**	(185)	(
Europe, Middle East and North Africa		**2,543**	136	1,
Asia Pacific		**483**	294	5
Other International		**(53)**	(20)	
Corporate and Other		**(282)**	(76)	(2
Consolidated income tax provision (benefit)	**$**	**4,633**	(485)	2,
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	**$**	**1,386**	(719)	1,
Lower 48		**4,932**	(1,122)	4
Canada		**458**	(326)	2
Europe, Middle East and North Africa		**1,167**	448	3,
Asia Pacific		**453**	962	1,
Other International		**(107)**	(64)	2
Corporate and Other		**(210)**	(1,880)	
Consolidated net income (loss) attributable to ConocoPhillips	**$**	**8,079**	(2,701)	7,

		Millions of Dollars		
		2021	2020	2
Investments in and Advances to Affiliates				
Alaska	$	**58**	62	
Lower 48		**242**	25	
Canada		**-**	-	
Europe, Middle East and North Africa		**797**	918	1,0
Asia Pacific		**5,603**	6,705	7,2
Other International		**1**	-	
Corporate and Other		**-**	-	
Consolidated investments in and advances to affiliates	$	**6,701**	7,710	8,4
Total Assets				
Alaska	$	**14,812**	14,623	15,4
Lower 48		**41,699**	11,932	14,4
Canada		**7,439**	6,863	6,3
Europe, Middle East and North Africa		**9,125**	8,756	9,2
Asia Pacific		**9,840**	11,231	13,
Other International		**1**	226	2
Corporate and Other		**7,745**	8,987	11,
Consolidated total assets	$	**90,661**	62,618	70,
Capital Expenditures and Investments				
Alaska	$	**982**	1,038	1,5
Lower 48		**3,129**	1,881	3,3
Canada		**203**	651	3
Europe, Middle East and North Africa		**534**	600	7
Asia Pacific		**390**	384	5
Other International		**33**	121	
Corporate and Other		**53**	40	
Consolidated capital expenditures and investments	$	**5,324**	4,715	6,6
Interest Income and Expense				
Interest income				
Alaska	$	**-**	-	
Lower 48		**-**	-	
Canada		**-**	-	
Europe, Middle East and North Africa		**2**	5	1
Asia Pacific		**9**	7	
Other International		**-**	-	
Corporate and Other		**22**	88	14
Interest and debt expense				
Corporate and Other	$	**884**	806	77
Sales and Other Operating Revenues by Product				
Crude oil	$	**23,648**	9,736	18,4
Natural gas		**16,904**	6,427	8,7
Natural gas liquids		**1,668**	528	8
Other*		**3,608**	2,093	4,5
Consolidated sales and other operating revenues by product	$	**45,828**	18,784	32,

**Includes LNG and bitumen.*

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
	2021	2020	2019	**2021**	2020	2
United States	**$ 34,847**	13,230	21,159	**50,580**	24,034	26,
Australia and Timor-Leste	**-**	605	1,647	**5,579**	6,676	7,
Canada	**2,494**	1,261	1,769	**6,608**	6,385	5,
China	**724**	460	772	**1,476**	1,491	1,
Indonesia[3]	**879**	689	875	**28**	464	6
Libya	**1,102**	155	1,103	**659**	670	6
Malaysia	**975**	610	1,230	**1,252**	1,501	1,
Norway	**2,563**	1,426	2,349	**4,681**	5,294	5,
United Kingdom	**2,236**	336	1,649	**1**	1	
Other foreign countries	**8**	12	14	**748**	1,087	1,
Worldwide consolidated	**$ 45,828**	18,784	32,567	**71,612**	47,603	50,

(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) Met held for sale criteria in 2021 in conjunction with our agreement to sell our subsidiary holding our Indonesia assets.

Oil and Gas Operations (Unaudited)

In accordance with FASB ASC Topic 932, "Extractive Activities—Oil and Gas," and regulatio
we are making certain supplemental disclosures about our oil and gas exploration and production

These disclosures include information about our consolidated oil and gas activities and our
share of equity affiliates' oil and gas activities in our operating segments. As a result, amounts
equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment
reported elsewhere in this report. Our disclosures by geographic area include the U.S., Canada, Eur
Middle East (inclusive of equity affiliates), and Africa.

As required by current authoritative guidelines, the estimated future date when an asset w
permanently shut down for economic reasons is based on historical 12-month first-of-month average prices a
costs. This estimated date when production will end affects the amount of estimated reserves. Theref
and cost levels change from year to year, the estimate of proved reserves also changes. Generally,
reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to PSCs, which are reported unde
interest" method, as well as variable-royalty regimes, and are subject to fluctuations in co
recoverable operating expenses and capital costs. If costs remain stable, reserve quantitie
recovery of costs will change inversely to changes in commodity prices. For example, if pri
then applicable reserve quantities would decline. At December 31, 2021, approximately 4 perce
proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting are
of our total proved reserves were under a variable-royalty regime, located in our Canada geograp
area.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by reg
SEC and FASB. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience
engineering data, can be estimated with reasonable certainty to be economically producible—from a given da
known reservoirs, and under existing economic conditions, operating methods, and govern
regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indica
reasonably certain, regardless of whether deterministic or probabilistic methods are used f
estimation. The project to extract the hydrocarbons must have commenced or the operator must be reaso
will commence the project within a reasonable time.

Proved reserves are further classified as either developed or undeveloped. Proved develope
reserves are reserves that can be expected to be recovered through existing wells with existing equipm
operating methods, or in which the cost of the required equipment is relatively minor compared with
new well, and through installed extraction equipment and infrastructure operational at the time of th
estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved r
expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively m
is required for recompletion. Reserves on undrilled acreage are limited to those directly offse
spacing areas that are reasonably certain of production when drilled, unless evidence provi
technologies exists that establishes reasonable certainty of economic producibility at great
defined by SEC regulations, reliable technologies may be used in reserve estimation when they hav
demonstrated in the field to provide reasonably certain results with consistency and repeatability in the forn
evaluated or in an analogous formation. The technologies and data used in the estimation of our prov
include, but are not limited to, performance-based methods, volumetric-based methods, geologic maps
interpretation, well logs, well test data, core data, analogy and statistical analysis.

We have a company-wide, comprehensive, SEC-compliant internal policy that governs the and reporting of proved reserves. This policy is applied by the geoscientists and reservoir engin business units around the world. As part of our internal control process, each business unit's reserv and controls are reviewed annually by an internal team which is headed by the company's Mana Compliance and Reporting. This team, composed of internal reservoir engineers, geoscient personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petrole consulting firm, reviews the business units' reserves for adherence to SEC guidelines and c through on-site visits, teleconferences and review of documentation. In addition to providing indep this internal team also ensures reserves are calculated using consistent and appropriate standa procedures. This team is independent of business unit line management and is responsible for reportin senior management. The team is responsible for communicating our reserves policy and procedu available for internal peer reviews and consultation on major projects or technical issues throughout th proved reserves held by consolidated companies and our share of equity affiliates have been estim ConocoPhillips.

During 2021, our processes and controls used to assess over 90 percent of proved reserve December 31, 2021, were reviewed by D&M. The purpose of their review was to assess whether the adeq effectiveness of our internal processes and controls used to determine estimates of proved reserves are with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overvie data, as well as the methods and assumptions used in estimating reserves. The data presented pertinent seismic information, geologic maps, well logs, production tests, material balance calculatio simulation models, well performance data, operating procedures and relevant economic criteria. Mana in retaining D&M to review its processes and controls was to provide objective third-party inp processes and controls. D&M's opinion was the general processes and controls employed by ConocoP estimating December 31, 2021, proved reserves for the properties reviewed are in accordance with th 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 contr preparation of the company's reserves estimates is the Manager of Reserves Compliance a This individual holds a master's degree in petroleum engineering. He is a member of the Societ Engineers with over 25 years of oil and gas industry experience and has held positions of i increasing responsibility in reservoir engineering, subsurface and asset management in the U.S. and several interna locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See t "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Re 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	Afri
Developed and Undeveloped							
Consolidated operations							
End of 2018	1,233	703	1,936	4	246	159	18
Revisions	40	(36)	4	(1)	18	(5)	23
Improved recovery	7	-	7	-	-	-	-
Purchases	-	1	1	-	-	-	-
Extensions and discoveries	25	226	251	2	-	11	-
Production	(74)	(95)	(169)	-	(36)	(31)	(1
Sales	-	(2)	(2)	-	(30)	-	-
End of 2019	1,231	797	2,028	5	198	134	19
Revisions	(297)	(126)	(423)	(2)	4	(4)	(
Improved recovery	-	-	-	-	-	3	-
Purchases	-	5	5	3	-	-	-
Extensions and discoveries	10	108	118	3	-	-	-
Production	(65)	(77)	(142)	(2)	(28)	(25)	(
Sales	-	(14)	(14)	(1)	-	-	-
End of 2020	879	693	1,572	6	174	108	19
Revisions	209	(52)	157	2	14	37	6
Improved recovery	1	-	1	-	-	-	-
Purchases	-	691	691	-	-	-	-
Extensions and discoveries	10	289	299	5	2	1	-
Production	(64)	(160)	(224)	(3)	(29)	(24)	(1
Sales	-	(9)	(9)	-	-	-	-
End of 2021	1,035	1,452	2,487	10	161	122	18
Equity affiliates							
End of 2018	-	-	-	-	-	78	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	73	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	68	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	63	-
Total company							
End of 2018	1,233	703	1,936	4	246	237	18
End of 2019	1,231	797	2,028	5	198	207	19
End of 2020	879	693	1,572	6	174	176	19
End of 2021	1,035	1,452	2,487	10	161	185	18

Years Ended December 31	Crude Oil Millions of Barrels						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
Developed							
Consolidated operations							
End of 2018	1,058	346	1,404	2	192	113	185
End of 2019	1,048	334	1,382	3	149	94	181
End of 2020	765	263	1,028	6	129	77	175
End of 2021	912	916	1,828	4	122	98	171
Equity affiliates							
End of 2018	-	-	-	-	-	78	-
End of 2019	-	-	-	-	-	73	-
End of 2020	-	-	-	-	-	68	-
End of 2021	-	-	-	-	-	63	-
Undeveloped							
Consolidated operations							
End of 2018	175	357	532	2	54	46	3
End of 2019	183	463	646	2	49	40	16
End of 2020	114	430	544	-	45	31	16
End of 2021	123	536	659	6	39	24	13
Equity affiliates							
End of 2018	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2021, includ

- *Revisions*: In 2021, Alaska upward revisions were primarily driven by higher prices. Downwa Lower 48 were due to development timing for specific well locations from unconventional plays of 203 mill technical revisions of 35 million barrels, partially offset by upward revisions due to higher prices of 1 barrels and additional infill drilling in the unconventional plays of 71 million barrels. Upward revisions in Europe w due to higher prices. In Asia Pacific/Middle East, increases were due to higher prices of 21 million barrels revisions of 16 million barrels.

  In 2020, Alaska downward revisions were primarily driven by lower prices of 243 million ba changes of 54 million barrels. Downward revisions in Lower 48 were due to lower prices of barrels and development timing for specific well locations from unconventional plays of 82 million barre offset by upward technical revisions and additional infill drilling in the unconventional plays of 45 million bar

  In 2019, Alaska upward revisions were due to cost and technical revisions of 74 million bar offset by downward price revisions of 34 million barrels. Upward revisions in Europe and Africa were primarily drilling and technical revisions. Downward revisions in Lower 48 were due to changes in development timing for locations from the unconventional plays of 71 million barrels and price revisions of 22 million barrels, partially upward revisions related to infill drilling and improved well performance of 57 million barrels.

- *Purchases*: In 2021, Lower 48 purchases were due to the Concho and Shell Permian acquisiti
- *Extensions and discoveries*: In 2021, extensions and discoveries in Lower 48 were due to planne
  specific well locations to and from the unconventional plays which more than offset the decreases
  development plan timing in the revisions category.

  In 2020, extensions and discoveries in Lower 48 were due to planned development to add
  locations from the unconventional plays which more than offset the decreases resulting from development pla
  revisions category.

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add
  locations from the unconventional plays which more than offset the decreases in the revisions category. In As
  East, increases due to sanctioning of development programs in China and Malaysia.
- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets.

Years Ended December 31	Natural Gas Liquids Millions of Barrels					
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacif Middle Ea
Developed and Undeveloped						
Consolidated operations						
End of 2018	106	222	328	1	17	3
Revisions	(1)	(11)	(12)	-	3	(1
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	62	62	1	-	-
Production	(5)	(28)	(33)	-	(3)	(1
Sales	-	-	-	-	(4)	-
End of 2019	100	245	345	2	13	1
Revisions	-	(26)	(26)	-	1	(1
Improved recovery	-	-	-	-	-	-
Purchases	-	2	2	2	-	-
Extensions and discoveries	-	41	41	1	-	-
Production	(6)	(27)	(33)	(1)	(2)	-
Sales	-	(5)	(5)	-	-	-
End of 2020	94	230	324	4	12	-
Revisions	(6)	213	207	-	1	-
Improved recovery	-	-	-	-	-	-
Purchases	-	72	72	-	-	-
Extensions and discoveries	-	82	82	2	-	-
Production	(6)	(50)	(56)	(1)	(2)	-
Sales	-	(1)	(1)	-	-	-
End of 2021	82	546	628	5	11	-
Equity affiliates						
End of 2018	-	-	-	-	-	42
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3
Sales	-	-	-	-	-	-
End of 2019	-	-	-	-	-	39
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3
Sales	-	-	-	-	-	-
End of 2020	-	-	-	-	-	36
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3
Sales	-	-	-	-	-	-
End of 2021	-	-	-	-	-	33
Total company						
End of 2018	106	222	328	1	17	45
End of 2019	100	245	345	2	13	40
End of 2020	94	230	324	4	12	36
End of 2021	82	546	628	5	11	33

Years Ended December 31	Natural Gas Liquids					
	Millions of Barrels					
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacif Middle Ea
Developed						
Consolidated operations						
End of 2018	106	97	203	-	15	3
End of 2019	100	99	199	1	10	1
End of 2020	94	83	177	4	9	-
End of 2021	82	334	416	3	9	-
Equity affiliates						
End of 2018	-	-	-	-	-	42
End of 2019	-	-	-	-	-	39
End of 2020	-	-	-	-	-	36
End of 2021	-	-	-	-	-	33
Undeveloped						
Consolidated operations						
End of 2018	-	125	125	1	2	-
End of 2019	-	146	146	1	3	-
End of 2020	-	147	147	-	3	-
End of 2021	-	212	212	2	2	-
Equity affiliates						
End of 2018	-	-	-	-	-	-
End of 2019	-	-	-	-	-	-
End of 2020	-	-	-	-	-	-
End of 2021	-	-	-	-	-	-

Notable changes in proved NGL reserves in the three years ended December 31, 2021, included:

- *Revisions*: In 2021, upward revisions in Lower 48 were due to conversion of acquired Concho stream contracts to a three-stream (crude oil, natural gas and natural gas liquids) basis, adding 182 million additional infill drilling in the unconventional plays of 44 million barrels, technical revisions of 21 million barrels and 28 million barrels, partially offset by downward revisions related to development timing for specific well locations from unconventional plays of 62 million barrels.

  In 2020, downward revisions in Lower 48 were due to lower prices of 33 million barrels and timing for specific well locations from unconventional plays of 20 million barrels, partially offset by upward te... additional infill drilling in the unconventional plays of 27 million barrels.

  In 2019, downward revisions in Lower 48 were due to changes in development timing for s... locations from the unconventional plays of 32 million barrels and price revisions of 11 million barrels, partially upward revisions related to infill drilling and improved well performance of 32 million barrels.

- *Purchases*: In 2021, Lower 48 purchases were due to the Shell Permian acquisition.

- *Extensions and discoveries*: In 2021, extensions and discoveries in Lower 48 were due to planne... specific well locations to add from the unconventional plays which more than offset the decreases... category.

  In 2020, extensions and discoveries in Lower 48 were due to planned development to add locations from the unconventional plays, which more than offset the decreases in the revisions category.

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add locations from the unconventional plays, which more than offset the decreases in the revisions category.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets.

Years Ended December 31	Natural Gas Billions of Cubic Feet						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2018	2,736	2,318	5,054	26	1,212	1,079	214
Revisions	30	(113)	(83)	(2)	160	147	21
Improved recovery	-	-	-	-	-	-	-
Purchases	-	2	2	-	-	-	-
Extensions and discoveries	7	483	490	23	-	1	-
Production	(85)	(252)	(337)	(4)	(178)	(250)	(11
Sales	-	(7)	(7)	-	(298)	-	-
End of 2019	2,688	2,431	5,119	43	896	977	224
Revisions	(607)	(439)	(1,046)	(15)	39	103	2
Improved recovery	-	-	-	-	-	-	-
Purchases	-	74	74	29	-	-	-
Extensions and discoveries	-	304	304	33	2	-	-
Production	(85)	(231)	(316)	(16)	(112)	(171)	(2
Sales	-	(39)	(39)	-	-	(58)	-
End of 2020	1,996	2,100	4,096	74	825	851	224
Revisions	715	41	756	15	54	60	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	2,438	2,438	-	-	-	-
Extensions and discoveries	-	822	822	46	2	-	-
Production	(86)	(473)	(559)	(30)	(113)	(147)	(7
Sales	-	(270)	(270)	-	-	-	-
End of 2021	2,625	4,658	7,283	105	768	764	217
Equity affiliates							
End of 2018	-	-	-	-	-	4,564	-
Revisions	-	-	-	-	-	(7)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	252	-
Production	-	-	-	-	-	(388)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	4,421	-
Revisions	-	-	-	-	-	(382)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	2	-
Extensions and discoveries	-	-	-	-	-	78	-
Production	-	-	-	-	-	(395)	-
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	3,724	-
Revisions	-	-	-	-	-	247	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	116	-
Production	-	-	-	-	-	(390)	-
Sales	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	3,697	-
Total company							
End of 2018	2,736	2,318	5,054	26	1,212	5,643	214
End of 2019	2,688	2,431	5,119	43	896	5,398	224
End of 2020	1,996	2,100	4,096	74	825	4,575	224
End of 2021	2,625	4,658	7,283	105	768	4,461	217

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afri
	Natural Gas Billions of Cubic Feet						
Developed							
Consolidated operations							
End of 2018	2,720	1,427	4,147	17	1,052	758	214
End of 2019	2,601	1,398	3,999	30	697	843	224
End of 2020	1,961	1,051	3,012	74	598	806	224
End of 2021	2,579	3,100	5,679	52	679	688	217
Equity affiliates							
End of 2018	-	-	-	-	-	4,059	-
End of 2019	-	-	-	-	-	3,898	-
End of 2020	-	-	-	-	-	3,293	-
End of 2021	-	-	-	-	-	3,204	-
Undeveloped							
Consolidated operations							
End of 2018	16	891	907	9	160	321	-
End of 2019	87	1,033	1,120	13	199	134	-
End of 2020	35	1,049	1,084	-	227	45	-
End of 2021	46	1,558	1,604	53	89	76	-
Equity affiliates							
End of 2018	-	-	-	-	-	505	-
End of 2019	-	-	-	-	-	523	-
End of 2020	-	-	-	-	-	431	-
End of 2021	-	-	-	-	-	493	-

Natural gas production in the reserves table may differ from gas production (delivered for sale) in disclosure, primarily because the quantities above include gas consumed in production operations. Quantities consumed in production not significant in the periods presented. The value of net production consumed in operations is no 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 2,748 Bcf, 2,286 Bcf and 3, December 31, 2021, 2020 and 2019, respectively. These volumes are not included in the calculation of our Standardize 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 Fah

Notable changes in proved natural gas reserves in the three years ended December 31, 2021, inc

- *Revisions*: In 2021, upward revisions in Alaska were due to higher prices of 587 Bcf and tech Lower 48, 1,128 Bcf. In 48, upward revisions of 614 Bcf were due to higher prices, additional infill drilling in unconventional plays of 277 Bcf and technical revisions of 60 Bcf, partially offset by downward revisions due to develop specific well locations from unconventional plays of 498 Bcf and conversion of previously acquired Perm volumes to a three-stream (crude oil, natural gas and natural gas liquids) basis of 412 Bcf. contracted revisions in Canada were due to higher prices of 29 Bcf, partially offset by downward revisions due to technical revis In Europe, upward revisions were primarily due to higher prices. Upward revisions in our consolidated Asia Pacific/Middle East were due to technical revisions of 76 Bcf, partially offset by price revisio our equity affiliates in Asia Pacific/Middle East, upward revisions were due to higher prices of 124 Bcf and cost revisions of 123 Bcf.

  In 2020, downward revisions in Alaska were primarily due to lower prices. In Lower 48, dow due to lower prices and 154 Bcf were due to development timing for specific well locations partially offset by technical revisions of 87 Bcf. Downward revisions in our equity affiliates due to lower prices of 426 Bcf, partially offset by performance revisions of 44 Bcf. Upward consolidated operations in Asia Pacific/Middle East were due to technical revisions of 88 Bcf and price re Bcf.

In 2019, upward revisions in Europe were due to technical and cost revisions. In Asia Pacif upward revisions were primarily due to the Indonesia Corridor PSC term extension. Downward revisions in L due to changes in development timing for specific well locations from the unconventional plays of 207 Bcf an of 125 Bcf, partially offset by upward revisions related to infill drilling and improved well performance

- *Purchases*: In 2021, Lower 48 purchases were due to the Concho and Shell Permian acquisit

  In 2020, Canada purchases were due to the acquisition of additional Montney acreage.

- *Extensions and discoveries*: In 2021, 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 Canada were primarily ongoing drilling successes in Montney.

  In 2020, extensions and discoveries in Lower 48 were due to planned development to add sp locations from the unconventional plays which more than offset the decreases resulting from development pla revisions category. Extensions and discoveries in Canada were primarily driven by ongoing drilling s Montney.

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add locations from the unconventional plays which more than offset the decreases in the revisions category. Exte discoveries in our equity affiliates were due to ongoing development in APLNG.

- *Sales*: In 2021, Lower 48 sales represent the disposition of noncore assets.

  In 2020, Asia Pacific/Middle East sales represent the disposition of the Australia-West asse

  In 2019, Europe sales represent the disposition of the U.K. assets.

Years Ended December 31	Bitumen
	Millions of Bar
	Car
Developed and Undeveloped	
Consolidated operations	
End of 2018	2
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2019	2
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2020	3
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2021	2
Equity affiliates	
End of 2018	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2019	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2020	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2021	
Total company	
End of 2018	2
End of 2019	2
End of 2020	3
End of 2021	2

Years Ended December 31	Bitumen Millions of Bar Can
Developed	
Consolidated operations	
End of 2018	1
End of 2019	1
End of 2020	1
End of 2021	1
Equity affiliates	
End of 2018	
End of 2019	
End of 2020	
End of 2021	
Undeveloped	
Consolidated operations	
End of 2018	
End of 2019	
End of 2020	2
End of 2021	1
Equity affiliates	
End of 2018	
End of 2019	
End of 2020	
End of 2021	

Notable changes in proved bitumen reserves in the three years ended December 31, 2021

- *Revisions*: In 2021, downward revisions of 64 million barrels were driven by changes costs and 39 million barrels due to changes in development timing for specific pad locatio Surmont development program, partially offset by upward revisions from price of 53 million

  In 2020, downward revisions in Canada were due to changes in development timing fo locations from the Surmont development program of 12 million barrels with the rem primarily related to lower prices.

  In 2019, upward revisions in Canada were due to technical revisions in Surmont of barrels partially offset by downward revisions due to changes in development timing for sp locations from the Surmont development program of 31 million barrels.

- *Extensions and discoveries*: In 2020, extensions and discoveries in Canada were primarily d development to add specific pad locations from the Surmont development program than offset the decrease in the revisions category.

  In 2019, extensions and discoveries in Canada were due to planned development to pad locations from the Surmont development program, which offset the decrease in the category of 31 million barrels.

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	Afri
Developed and Undeveloped							
Consolidated operations							
End of 2018	1,795	1,312	3,107	245	465	342	224
Revisions	44	(67)	(23)	36	48	19	26
Improved recovery	7	-	7	-	-	-	-
Purchases	-	2	2	-	-	-	-
Extensions and discoveries	26	368	394	38	-	11	-
Production	(93)	(165)	(258)	(23)	(68)	(74)	(1
Sales	-	(3)	(3)	-	(85)	-	-
End of 2019	1,779	1,447	3,226	296	360	298	234
Revisions	(398)	(226)	(624)	(20)	12	13	(3
Improved recovery	-	-	-	-	-	3	-
Purchases	-	19	19	10	-	-	-
Extensions and discoveries	10	200	210	95	-	-	-
Production	(85)	(142)	(227)	(25)	(49)	(55)	(3
Sales	-	(25)	(25)	(1)	-	(10)	-
End of 2020	1,306	1,273	2,579	355	323	249	228
Revisions	322	168	490	(45)	23	47	6
Improved recovery	1	-	1	-	-	-	-
Purchases	-	1,169	1,169	-	-	-	-
Extensions and discoveries	10	508	518	15	3	1	-
Production	(84)	(289)	(373)	(35)	(50)	(48)	(1
Sales	-	(54)	(54)	-	-	-	-
End of 2021	1,555	2,775	4,330	290	299	249	220
Equity affiliates							
End of 2018	-	-	-	-	-	880	-
Revisions	-	-	-	-	-	(1)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	42	-
Production	-	-	-	-	-	(73)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	848	-
Revisions	-	-	-	-	-	(63)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	13	-
Production	-	-	-	-	-	(73)	-
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	725	-
Revisions	-	-	-	-	-	42	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	19	-
Production	-	-	-	-	-	(73)	-
Sales	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	713	-
Total company							
End of 2018	1,795	1,312	3,107	245	465	1,222	224
End of 2019	1,779	1,447	3,226	296	360	1,146	234
End of 2020	1,306	1,273	2,579	355	323	974	228
End of 2021	1,555	2,775	4,330	290	299	962	220

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	Afric
Developed							
Consolidated operations							
End of 2018	1,617	681	2,298	160	382	244	221
End of 2019	1,582	666	2,248	197	275	236	218
End of 2020	1,186	521	1,707	140	238	211	212
End of 2021	1,424	1,767	3,191	166	244	212	207
Equity affiliates							
End of 2018	-	-	-	-	-	796	-
End of 2019	-	-	-	-	-	761	-
End of 2020	-	-	-	-	-	653	-
End of 2021	-	-	-	-	-	631	-
Undeveloped							
Consolidated operations							
End of 2018	178	631	809	85	83	98	3
End of 2019	197	781	978	99	85	62	16
End of 2020	120	752	872	215	85	38	16
End of 2021	131	1,008	1,139	124	55	37	13
Equity affiliates							
End of 2018	-	-	-	-	-	84	-
End of 2019	-	-	-	-	-	87	-
End of 2020	-	-	-	-	-	72	-
End of 2021	-	-	-	-	-	82	-

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six MC converts to one BOE.

Proved Undeveloped Reserves

The following table shows changes in total proved undeveloped reserves for 2021:

	Proved Undeve Reserves Millions O
End of 2020	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Sales	
Transfers to proved developed	
End of 2021	

Downward revisions were driven by changes in development timing of 389 MMBOE primarily in No bitumen negative revisions in Canada due to changes in carbon tax costs of 65 MMBOE, partially offset by u for Lower 48 infill drilling of 162 MMBOE and higher prices of 125 MMBOE.

Purchases were driven by Lower 48 due to the Concho acquisition.

Extensions and discoveries were largely driven by an addition of 399 MMBOE in Lower 48 for the c development of unconventional plays. The remaining extensions and discoveries were driven by the continued dev planned in the other geographic regions.

Transfers to proved developed reserves were driven by the ongoing development of our assets. Ap percent of the transfers were from the development of our Lower 48 unconventional plays. The remainder of tran development other across the geographic regions.

At December 31, 2021, our PUDs represented 24 percent of total proved reserves, compared with December 31, 2020. Costs incurred for the year ended December 31, 2021, relating to the development of PUDs were portion of our costs incurred each year relates to development projects where the PUDs will be converted to proved de reserves in future years.
At the end of 2021, approximately 93 percent of total PUDs were under development or scheduled development within five years of initial disclosure, including all of our Lower 48 PUDs. The remaining PUDs are in major de areas which are currently producing and within our Canada and Asia Pacific/Middle East geographic areas.

Results of Operations

The company's results of operations from oil and gas activities for the years 2021, 2020 and 2019 the following tables. Nonoil and gas activities, such as pipeline and marine operations, LNG operations, crude oil and g activities, and the profit element of transportation operations in which we have an ownership interest are excluded. 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 worki royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the produc a final delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the produ a final delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from t sale of hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment a 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 a other miscellaneous expenses.

Results of Operations

Year Ended December 31, 2021		Millions of Dollars						
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Oth Are
Consolidated operations									
Sales	$	4,832	14,093	18,925	1,219	3,568	2,525	917	-
Transfers		4	-	4	-	-	-	-	-
Transportation costs		(626)	-	(626)	-	-	-	-	-
Other revenues		14	135	149	323	(5)	237	141	(16
Total revenues		4,224	14,228	18,452	1,542	3,563	2,762	1,058	(16
Production costs excluding taxes		1,073	2,414	3,487	518	487	466	43	-
Taxes other than income taxes		442	937	1,379	23	36	91	1	1
Exploration expenses		80	98	178	39	21	51	2	15
Depreciation, depletion and amortization		864	4,053	4,917	383	844	787	35	-
Impairments		5	(8)	(3)	6	(24)	7	-	-
Other related expenses		(31)	12	(19)	(22)	(42)	4	4	12
Accretion		71	47	118	10	70	26	-	-
		1,720	6,675	8,395	585	2,171	1,330	973	(18
Income tax provision (benefit)		378	1,467	1,845	145	1,673	494	870	(5
Results of operations	$	1,342	5,208	6,550	440	498	836	103	(13
Equity affiliates									
Sales	$	-	-	-	-	-	745	-	-
Transfers		-	-	-	-	-	1,797	-	-
Transportation costs		-	-	-	-	-	-	-	-
Other revenues		-	-	-	-	-	5	-	-
Total revenues		-	-	-	-	-	2,547	-	-
Production costs excluding taxes		-	-	-	-	-	329	-	-
Taxes other than income taxes		-	-	-	-	-	824	-	-
Exploration expenses		-	-	-	-	-	268	-	-
Depreciation, depletion and amortization		-	-	-	-	-	593		
Impairments		-	-	-	-	-	718	-	-
Other related expenses		-	-	-	-	-	3	-	-
Accretion		-	-	-	-	-	17	-	-
		-	-	-	-	-	(205)	-	-
Income tax provision (benefit)		-	-	-	-	-	(42)	-	-
Results of operations	$	-	-	-	-	-	(163)	-	-

Year Ended December 31, 2020		Millions of Dollars							
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	To
Consolidated operations										
Sales	$	2,944	3,421	6,365	230	1,560	1,717	129	-	10,0
Transfers		4	-	4	-	-	191	-	-	1
Transportation costs		(587)	-	(587)	-	-	(19)	-	-	(6
Other revenues		(1)	(20)	(21)	40	(21)	576	11	10	5
Total revenues		2,360	3,401	5,761	270	1,539	2,465	140	10	10,1
Production costs excluding taxes		1,058	1,399	2,457	366	417	478	21	2	3,7
Taxes other than income taxes		296	263	559	16	30	42	3	1	6
Exploration expenses		1,099	73	1,172	40	52	71	13	108	1,4
Depreciation, depletion and amortization		840	2,544	3,384	335	755	808	8	-	5,2
Impairments		-	804	804	3	5	-	-	-	8
Other related expenses		46	5	51	5	(58)	(25)	(29)	2	(
Accretion		72	46	118	8	73	33	-	-	2
		(1,051)	(1,733)	(2,784)	(503)	265	1,058	124	(103)	(1,9
Income tax provision (benefit)		(271)	(430)	(701)	(191)	116	277	88	(20)	(4
Results of operations	$	(780)	(1,303)	(2,083)	(312)	149	781	36	(83)	(1,
Equity affiliates										
Sales	$	-	-	-	-	-	483	-	-	4
Transfers		-	-	-	-	-	1,205	-	-	1,2
Transportation costs		-	-	-	-	-	-	-	-	
Other revenues		-	-	-	-	-	8	-	-	
Total revenues		-	-	-	-	-	1,696	-	-	1,6
Production costs excluding taxes		-	-	-	-	-	289	-	-	2
Taxes other than income taxes		-	-	-	-	-	502	-	-	5
Exploration expenses		-	-	-	-	-	20	-	-	
Depreciation, depletion and amortization		-	-	-	-	-	569	-	-	5
Impairments		-	-	-	-	-	-	-	-	
Other related expenses		-	-	-	-	-	(2)	-	-	
Accretion		-	-	-	-	-	15	-	-	
		-	-	-	-	-	303	-	-	3
Income tax provision (benefit)		-	-	-	-	-	39	-	-	
Results of operations	$	-	-	-	-	-	264	-	-	2

Year Ended December 31, 2019		Millions of Dollars							
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Ot Ar
Consolidated operations									
Sales	$	4,883	6,356	11,239	709	3,207	3,032	919	
Transfers		4	-	4	-	-	449	-	
Transportation costs		(629)	-	(629)	-	-	(41)	-	
Other revenues		61	78	139	86	1,785	12	101	3
Total revenues		4,319	6,434	10,753	795	4,992	3,452	1,020	3
Production costs excluding taxes		1,235	1,578	2,813	380	741	619	70	
Taxes other than income taxes		308	437	745	18	32	54	3	
Exploration expenses		97	430	527	32	69	80	5	
Depreciation, depletion and amortization		700	2,804	3,504	230	842	1,172	37	
Impairments		-	402	402	2	1	-	-	
Other related expenses		(12)	116	104	(38)	(42)	58	22	
Accretion		62	49	111	7	142	43	-	
		1,929	618	2,547	164	3,207	1,426	883	2
Income tax provision (benefit)		444	147	591	(74)	591	458	833	
Results of operations	$	1,485	471	1,956	238	2,616	968	50	2
Equity affiliates									
Sales	$	-	-	-	-	-	599	-	
Transfers		-	-	-	-	-	2,229	-	
Transportation costs		-	-	-	-	-	-	-	
Other revenues		-	-	-	-	-	31	-	
Total revenues		-	-	-	-	-	2,859	-	
Production costs excluding taxes		-	-	-	-	-	335	-	
Taxes other than income taxes		-	-	-	-	-	820	-	
Exploration expenses		-	-	-	-	-	-	-	
Depreciation, depletion and amortization		-	-	-	-	-	579	-	
Impairments		-	-	-	-	-	-	-	
Other related expenses		-	-	-	-	-	11	-	
Accretion		-	-	-	-	-	16	-	
		-	-	-	-	-	1,098	-	
Income tax provision (benefit)		-	-	-	-	-	170	-	
Results of operations	$	-	-	-	-	-	928	-	

Statistics

Net Production	2021	2020	2
	Thousands of Barrels Dai		
Crude Oil			
Consolidated operations			
Alaska	**178**	181	2
Lower 48	**447**	213	2
United States	**625**	394	4
Canada	**8**	6	
Europe	**81**	78	1
Asia Pacific	**65**	69	
Africa	**37**	8	
Total consolidated operations	**816**	555	6
Equity affiliates—Asia Pacific/Middle East	**13**	13	
Total company	**829**	568	7
*Delaware Basin Area (Lower 48)**	***162***	*28*	
*Greater Prudhoe Area (Alaska)**	***67***	*68*	
Natural Gas Liquids			
Consolidated operations			
Alaska	**16**	16	
Lower 48	**110**	74	
United States	**126**	90	
Canada	**4**	2	
Europe	**4**	4	
Asia Pacific	**-**	1	
Total consolidated operations	**134**	97	1
Equity affiliates—Asia Pacific/Middle East	**8**	8	
Total company	**142**	105	1
*Delaware Basin Area (Lower 48)**	***27***	*11*	
*Greater Prudhoe Area (Alaska)**	***16***	*15*	
Bitumen			
Consolidated operations—Canada	**69**	55	
Total company	**69**	55	
Natural Gas	Millions of Cubic Feet Dai		
Consolidated operations			
Alaska	**16**	10	
Lower 48	**1,340**	585	6
United States	**1,356**	595	6
Canada	**80**	40	
Europe	**298**	270	4
Asia Pacific	**360**	429	6
Africa	**15**	5	
Total consolidated operations	**2,109**	1,339	1,7
Equity affiliates—Asia Pacific/Middle East	**1,053**	1,055	1,0
Total company	**3,162**	2,394	2,8
*Delaware Basin Area (Lower 48)**	***584***	*99*	
*Greater Prudhoe Area (Alaska)**	***12***	*4*	

**At year-end 2021, the Delaware Basin Area in Lower 48 contained more than 15 percent of our total proved re*
2021, 2020 and 2019, the Greater Prudhoe Area in Alaska contained more than 15 percent of our total proved reserves.

Average Sales Prices		2021	2020	2
Crude Oil Per Barrel				
Consolidated operations				
Alaska*	$	**60.81**	33.72	55
Lower 48		**66.12**	35.17	55
United States		**64.53**	34.48	55
Canada		**56.38**	23.57	40
Europe		**68.94**	42.80	65
Asia Pacific		**70.36**	42.84	65
Africa		**69.06**	48.64	64
Total international		**68.85**	42.39	64
Total consolidated operations		**65.53**	36.69	58
Equity affiliates—Asia Pacific/Middle East		**69.45**	39.02	61
Total operations		**65.59**	36.75	58
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**30.63**	12.13	16
United States		**30.63**	12.13	16
Canada		**31.18**	5.41	19
Europe		**43.97**	23.27	29
Asia Pacific		**-**	33.21	37
Total international		**37.50**	20.25	32
Total consolidated operations		**31.04**	12.90	18
Equity affiliates—Asia Pacific/Middle East		**54.16**	32.69	36
Total operations		**32.45**	14.61	20
Bitumen Per Barrel				
Consolidated operations—Canada	$	**37.52**	8.02**	31
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**2.81**	2.91	3
Lower 48		**4.38**	1.65	2
United States		**4.38**	1.66	2
Canada		**2.54**	1.21	0
Europe		**13.75**	3.23	4
Asia Pacific*		**6.56**	5.27	5
Africa		**3.73**	3.71	4
Total international		**8.91**	4.31	5
Total consolidated operations		**6.00**	3.13	4
Equity affiliates—Asia Pacific/Middle East		**5.31**	3.71	6
Total operations		**5.77**	3.38	4

**Average sales prices for Alaska crude oil and Asia Pacific natural gas above reflect a reduction for transportatio have an ownership interest that are incurred subsequent to the terminal point of the production function. Accor sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results*
***Average sales prices include unutilized transportation costs.*

		2021	2020	2
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**14.92**	14.60	15
Lower 48		**8.48**	9.93	9
United States		**9.78**	11.51	11
Canada		**15.10**	14.29	16
Europe		**9.88**	8.97	11
Asia Pacific		**10.21**	9.26	8
Africa		**2.95**	6.38	4
Total international		**10.53**	10.11	10
Total consolidated operations		**9.99**	10.99	10
Equity affiliates—Asia Pacific/Middle East		**4.60**	4.01	4
Average Production Costs Per Barrel—Bitumen				
Consolidated operations—Canada	$	**13.41**	12.45	13
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**6.15**	4.08	3
Lower 48		**3.29**	1.87	2
United States		**3.87**	2.62	3
Canada		**0.67**	0.62	0
Europe		**0.73**	0.65	0
Asia Pacific		**1.99**	0.81	0
Africa		**0.07**	0.91	0
Total international		**1.06**	0.72	0
Total consolidated operations		**3.06**	1.91	2
Equity affiliates—Asia Pacific/Middle East		**11.52**	6.96	11
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**12.02**	11.59	8
Lower 48		**14.24**	18.05	17
United States		**13.79**	15.86	14
Canada		**11.16**	13.08	10
Europe		**17.13**	16.24	12
Asia Pacific		**17.25**	15.66	16
Africa		**2.40**	2.43	2
Total international		**14.25**	15.01	12
Total consolidated operations		**13.92**	15.54	13
Equity affiliates—Asia Pacific/Middle East		**8.29**	7.89	8

**Includes bitumen.*

Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and wells in the years ended December 31, 2021, 2020 and 2019. A "development well" is a well drille proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "explorat well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a Exploratory wells also include wells drilled in areas near or offsetting current production, o well density or production history have not achieved statistical certainty of results. Excluded fro exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation w Canada and CBM test wells located in Asia Pacific/Middle East.

Net Wells Completed

	Productive			Dry		
	2021	2020	2019	**2021**	2020	2
Exploratory						
Consolidated operations						
Alaska	**-**	-	7	**1**	3	
Lower 48	**87**	3	35	**-**	-	
United States	**87**	3	42	**1**	3	
Canada	**12**	23	-	**-**	-	
Europe	**-**	-	1	**-**	*	
Asia Pacific/Middle East	*****	*	1	*****	*	
Africa	**-**	-	-	**-**	*	
Other areas	**-**	-	-	**-**	*	
Total consolidated operations	**99**	26	44	**1**	3	
Equity affiliates						
Asia Pacific/Middle East	**3**	8	8	**-**	-	
Total equity affiliates	**3**	8	8	**-**	-	
Development						
Consolidated operations						
Alaska	**1**	7	12	**-**	-	
Lower 48	**339**	127	255	**-**	-	
United States	**340**	134	267	**-**	-	
Canada	**2**	-	2	**-**	-	
Europe	**7**	7	6	**-**	-	
Asia Pacific/Middle East	**21**	16	21	**-**	-	
Africa	**1**	2	2	**-**	-	
Other areas	**-**	-	-	**-**	-	
Total consolidated operations	**371**	159	298	**-**	-	
Equity affiliates						
Asia Pacific/Middle East	**30**	109	106	**-**	-	
Total equity affiliates	**30**	109	106	**-**	-	

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2021, and inclu
process of drilling or in active completion. It also represents gross and net productive wells
producing wells and wells capable of production at December 31, 2021.

Wells at December 31, 2021

	In Progress		Productive			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	N
Consolidated operations						
Alaska	2	1	1,602	940	-	
Lower 48	665	337	16,306	8,015	5,091	2,21
United States	667	338	17,908	8,955	5,091	2,21
Canada	18	15	186	94	149	14
Europe	11	1	494	84	59	2
Asia Pacific/Middle East	15	7	351	166	38	1
Africa	7	1	858	140	10	2
Other areas	-	-	-	-	-	
Total consolidated operations	718	362	19,797	9,439	5,347	2,38
Equity affiliates						
Asia Pacific/Middle East	130	25	-	-	4,908	1,17
Total equity affiliates	130	25	-	-	4,908	1,17

Acreage at December 31, 2021

	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	N
Consolidated operations				
Alaska	663	479	1,341	1,3
Lower 48	4,096	2,538	10,514	8,2
United States	4,759	3,017	11,855	9,5
Canada	297	219	3,433	1,9
Europe	430	50	938	37
Asia Pacific/Middle East	921	421	10,451	6,9
Africa	358	58	12,545	2,0
Other areas	-	-	156	12
Total consolidated operations	6,765	3,765	39,378	20,9
Equity affiliates				
Asia Pacific/Middle East	1,039	248	3,807	85
Total equity affiliates	1,039	248	3,807	85

Costs Incurred

Year Ended December 31	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas
2021								
Consolidated operations								
Unproved property acquisition	$ 1	11,261	11,262	4	-	-	-	-
Proved property acquisition	-	16,101	16,101	1	-	-	-	-
	1	27,362	27,363	5	-	-	-	-
Exploration	84	765	849	80	31	51	2	40
Development	949	2,461	3,410	175	398	433	24	-
	$ 1,034	30,588	31,622	260	429	484	26	40
Equity affiliates								
Unproved property acquisition	$ -	-	-	-	-	-	-	-
Proved property acquisition			-					
	-	-	-	-	-	-	-	-
Exploration	-	-	-	-	-	5	-	-
Development	-	-	-	-	-	21	-	-
	$ -	-	-	-	-	26	-	-
2020								
Consolidated operations								
Unproved property acquisition	$ 4	10	14	378	-	3	-	9
Proved property acquisition	-	62	62	129	-	-	-	-
	4	72	76	507	-	3	-	9
Exploration	287	116	403	218	110	32	4	38
Development	745	1,758	2,503	102	451	427	18	-
	$ 1,036	1,946	2,982	827	561	462	22	47
Equity affiliates								
Unproved property acquisition	$ -	-	-	-	-	-	-	-
Proved property acquisition	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
Exploration	-	-	-	-	-	12	-	-
Development	-	-	-	-	-	282	-	-
	$ -	-	-	-	-	294	-	-
2019								
Consolidated operations								
Unproved property acquisition	$ 101	45	146	14	-	-	-	197
Proved property acquisition	1	116	117	-	-	115	-	-
	102	161	263	14	-	115	-	197
Exploration	281	390	671	200	119	66	8	39
Development	1,125	3,028	4,153	215	625	486	22	-
	$ 1,508	3,579	5,087	429	744	667	30	236
Equity affiliates								
Unproved property acquisition	$ -	-	-	-	-	62	-	-
Proved property acquisition	-	-	-	-	-	-	-	-
	-	-	-	-	-	62	-	-
Exploration	-	-	-	-	-	23	-	-
Development	-	-	-	-	-	171	-	-
	$ -	-	-	-	-	256	-	-

Capitalized Costs

At December 31	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Othe Area
2021								
Consolidated operations								
Proved property	$ 22,750	58,561	81,311	7,380	14,514	12,226	966	-
Unproved property	1,402	7,704	9,106	1,517	155	92	114	9
	24,152	66,265	90,417	8,897	14,669	12,318	1,080	9
Accumulated depreciation, depletion and amortization	11,945	29,975	41,920	2,749	10,166	9,240	422	9
	$ 12,207	36,290	48,497	6,148	4,503	3,078	658	-
Equity affiliates								
Proved property	$ -	-	-	-	-	10,357	-	-
Unproved property	-	-	-	-	-	2,162	-	-
	-	-	-	-	-	12,519	-	-
Accumulated depreciation, depletion and amortization	-	-	-	-	-	8,539	-	-
	$ -	-	-	-	-	3,980	-	-
2020								
Consolidated operations								
Proved property	$ 21,819	37,452	59,271	7,255	14,931	11,913	942	-
Unproved property	1,398	631	2,029	1,529	151	89	114	229
	23,217	38,083	61,300	8,784	15,082	12,002	1,056	229
Accumulated depreciation, depletion and amortization	11,098	27,948	39,046	2,431	10,015	8,567	387	9
	$ 12,119	10,135	22,254	6,353	5,067	3,435	669	220
Equity affiliates								
Proved property	$ -	-	-	-	-	10,310	-	-
Unproved property	-	-	-	-	-	2,187	-	-
	-	-	-	-	-	12,497	-	-
Accumulated depreciation, depletion and amortization	-	-	-	-	-	6,959	-	-
	$ -	-	-	-	-	5,538	-	-

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and G
Quantities

In accordance with SEC and FASB requirements, amounts were computed using 12-month averag (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 per 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-e conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over ti become available. Probable or possible reserves, which may become proved in the future, were not considered. The also requires assumptions as to the timing of future production of proved reserves and the timing and amount c 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 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	Afric
2021							
Consolidated operations							
Future cash inflows	$ 65,910	125,197	191,107	10,847	21,670	11,583	15,77
Less:							
Future production costs	34,444	43,034	77,478	4,960	6,090	4,987	801
Future development costs	8,033	13,386	21,419	923	3,960	1,314	413
Future income tax provisions	5,310	13,167	18,477	117	8,345	1,542	13,50
Future net cash flows	18,123	55,610	73,733	4,847	3,275	3,740	1,05
10 percent annual discount	7,963	22,290	30,253	1,639	696	930	440
Discounted future net cash flows	$ 10,160	33,320	43,480	3,208	2,579	2,810	618
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	27,851	-
Less:							
Future production costs	-	-	-	-	-	15,491	-
Future development costs	-	-	-	-	-	1,649	-
Future income tax provisions	-	-	-	-	-	3,071	-
Future net cash flows	-	-	-	-	-	7,640	-
10 percent annual discount	-	-	-	-	-	2,640	-
Discounted future net cash flows	$ -	-	-	-	-	5,000	-
Total company							
Discounted future net cash flows	$ 10,160	33,320	43,480	3,208	2,579	7,810	618

	Millions of Dollars						
	Alaska	Lower 48	Total U.S.	Canada*	Europe	Asia Pacific/ Middle East	A
2020							
Consolidated operations							
Future cash inflows	$ 30,145	31,533	61,678	4,198	9,857	7,940	9
Less:							
Future production costs	22,905	17,582	40,487	4,316	4,770	3,838	1
Future development costs	7,932	12,799	20,731	750	3,688	1,289	
Future income tax provisions	-	376	376	-	267	1,075	7
Future net cash flows	(692)	776	84	(868)	1,132	1,738	
10 percent annual discount	(1,501)	(820)	(2,321)	(396)	117	406	
Discounted future net cash flows	$ 809	1,596	2,405	(472)	1,015	1,332	
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	17,284	
Less:							
Future production costs	-	-	-	-	-	10,239	
Future development costs	-	-	-	-	-	1,186	
Future income tax provisions	-	-	-	-	-	1,728	
Future net cash flows	-	-	-	-	-	4,131	
10 percent annual discount	-	-	-	-	-	1,269	
Discounted future net cash flows	$ -	-	-	-	-	2,862	
Total company							
Discounted future net cash flows	$ 809	1,596	2,405	(472)	1,015	4,194	

**Undiscounted future net cash flows related to the proved oil and gas reserves disclosed for Canada for the year ending are negative due to the inclusion of asset retirement costs and certain indirect costs in the calculation of the standardized measure of discounted flows. These costs are not requirements to be considered in the economic limit test for proved developed reserves as defined in Regulation S-X Rule 4-10. flows for Canada were also impacted by lower 12-month average pricing for bitumen and crude oil in 2020. Commodity prices have since improved environment.*

		Millions of Dollars						
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
2019								
Consolidated operations								
Future cash inflows	$	70,341	53,400	123,741	8,244	16,919	13,084	15,58
Less:								
Future production costs		40,464	22,194	62,658	4,525	5,843	5,162	1,31
Future development costs		9,721	14,083	23,804	577	4,143	2,179	484
Future income tax provisions		3,904	2,793	6,697	-	4,201	1,931	12,74
Future net cash flows		16,252	14,330	30,582	3,142	2,732	3,812	1,03
10 percent annual discount		6,571	4,311	10,882	1,198	558	835	460
Discounted future net cash flows	$	9,681	10,019	19,700	1,944	2,174	2,977	577
Equity affiliates								
Future cash inflows	$	-	-	-	-	-	31,671	-
Less:								
Future production costs		-	-	-	-	-	16,157	-
Future development costs		-	-	-	-	-	1,218	-
Future income tax provisions		-	-	-	-	-	3,086	-
Future net cash flows		-	-	-	-	-	11,210	-
10 percent annual discount		-	-	-	-	-	4,040	-
Discounted future net cash flows	$	-	-	-	-	-	7,170	-
Total company								
Discounted future net cash flows	$	9,681	10,019	19,700	1,944	2,174	10,147	577

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars							
	Consolidated Operations			Equity Affiliates			Total Compa	
	2021	2020	2019	**2021**	2020	2019	**2021**	2020
Discounted future net cash flows at the beginning of the year	$ **4,674**	27,372	35,434	**2,862**	7,170	7,929	**7,536**	34,542
Changes during the year								
Revenues less production costs for the year	**(20,000)**	(5,198)	(13,424)	**(1,389)**	(897)	(1,673)	**(21,389)**	(6,095
Net change in prices and production costs	**50,956**	(34,307)	(13,538)	**3,822**	(4,769)	(422)	**54,778**	(39,076
Extensions, discoveries and improved recovery, less estimated future costs	**10,420**	887	2,985	**(44)**	22	260	**10,376**	909
Development costs for the year	**4,396**	3,593	5,333	**91**	192	239	**4,487**	3,785
Changes in estimated future development costs	**(33)**	754	559	**(104)**	(205)	(21)	**(137)**	549
Purchases of reserves in place, less estimated future costs	**17,833**	1	10	**-**	(3)	-	**17,833**	(2)
Sales of reserves in place, less estimated future costs	**(468)**	(302)	(1,997)	**-**	-	-	**(468)**	(302)
Revisions of previous quantity estimates	**2,985**	(2,299)	2,099	**178**	(42)	69	**3,163**	(2,341
Accretion of discount	**964**	3,984	5,144	**344**	804	869	**1,308**	4,788
Net change in income taxes	**(19,032)**	10,189	4,767	**(760)**	590	(80)	**(19,792)**	10,779
Total changes	**48,021**	(22,698)	(8,062)	**2,138**	(4,308)	(759)	**50,159**	(27,006
Discounted future net cash flows at year end	$ **52,695**	4,674	27,372	**5,000**	2,862	7,170	**57,695**	7,536

- The net change in prices and production costs is the beginning-of-year reserve-production fore
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 rec
calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-mon
prices, less future estimated costs, discounted at 10 percent.
- Revisions of previous quantity estimates are calculated using production forecast changes for t
including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated c
at 10 percent.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less f
production and development costs.
- The net change in income taxes is the annual change in the discounted future income tax prov

Item 9. Changes in and Disagreements with Accountants on Acc Financial Disclosure

None.

Item 9A. Controls and Procedures

We maintain disclosure controls and procedures designed to ensure information required to reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act) summarized, processed and reported within the time periods specified in Securities and Exchange Con and forms, and that such information is accumulated and communicated to management, inclu principal executive and principal financial officers, as appropriate, to allow timely decisions regardin disclosure. As of December 31, 2021, with the participation of our management, our Chairman and Ch Officer (principal executive officer) and our Executive Vice President and Chief Financial Officer (pr officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosu procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Cha Executive Officer and our Executive Vice President and Chief Financial Officer concluded ou controls and procedures were operating effectively as of December 31, 2021.

There have been no changes in our internal control over financial reporting, as defined in R the Act, in the period covered by this report that have materially affected, or are reasonably likely 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 75 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm
This report is included in Item 8 on page 76 and is incorporated herein by reference.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governanc

Information regarding our executive officers appears in Part I of this report on page 30.

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 Ethi our principal executive officer, principal financial officer, principal accounting officer and person similar functions. We have posted a copy of our Code of Ethics on the “Corporate Governance” sec internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of th Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendm waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the “ Governance” section of our internet website.

All other information required by Item 10 of Part III will be included in our Proxy Statemen 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 3 incorporated herein by reference.*

Item 11. Executive Compensation

Information required by Item 11 of Part III will be included in our Proxy Statement relating Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022 incorporated herein by reference.*

Item 12. Security Ownership of Certain Beneficial Owners and M and Related Stockholder Matters

Information required by Item 12 of Part III will be included in our Proxy Statement relating Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022 incorporated herein by reference.*

Item 13. Certain Relationships and Related Transactions, and Di Independence

Information required by Item 13 of Part III will be included in our Proxy Statement relating Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022 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 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022 incorporated herein by reference.*

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other i appearing in 2022 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be file 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 Finar
which appears on page 74 are filed as part of this annual report.

2. Financial Statement Schedules

All financial statement schedules are omitted because they are not required, not sig
applicable or the information is shown in another schedule, the financial statements
consolidated financial statements.

3. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 181 through 185, are filed as
this annual report.

ConocoPhillips

Index to Exhibits

Exhibit No.	Description	Incorporated by I		
		Exhibit	Form	F
2.1	Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012.	2.1	8-K	00
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.	2.1	10-Q	00
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.	2.2	8-K	00
2.4	Agreement and Plan of Merger, dated as of October 18, 2020, among ConocoPhillips, Falcon Merger Sub Corp. and Concho Resources Inc.	2.1	8-K	00
3.1	Amended and Restated Certificate of Incorporation.	3.1	10-Q	00
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips.	3.2	8-K	00
3.3	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015.	3.1	8-K	00
3.4*	Restated Certificate of Incorporation of ConocoPhillips Company, dated February 6, 2019.			
	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.	4.1	10-K	00
10.1	1986 Stock Plan of Phillips Petroleum Company.	10.11	10-K	00
10.2	1990 Stock Plan of Phillips Petroleum Company.	10.12	10-K	00
10.5	Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012.	10.14	10-Q	00
10.7	Omnibus Securities Plan of Phillips Petroleum Company.	10.19	10-K	00
10.10.1	Amended and Restated ConocoPhillips Key Employee Supplemental Retirement Plan, dated January 1, 2020.	10.10.1	10-K	00
10.10.2	Eighth Amendment to Retirement Plans as amended and restated effective January 1, 2016.	10.1	10-Q	00

10.11.1	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated January 1, 2020.	10.11.1	10-K	00
10.11.2	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated January 1, 2020.	10.11.2	10-K	00
10.12	2002 Omnibus Securities Plan of Phillips Petroleum Company.	10.26	10-K	00
10.15	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips.	10.17	10-K	00
10.16.1	Rabbi Trust Agreement dated December 17, 1999.	10.11	10-K	00
10.16.2	Amendment to Rabbi Trust Agreement dated February 25, 2002.	10.39.1	10-K	00
10.16.3	Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998.	10.19	10-K	00
10.16.4	First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999.	10.17.4	10-K	00
10.16.5	Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002.	10.17.5	10-K	00
10.16.6	Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006.	10.17.6	10-K	00
10.16.7	Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012.	10.17.7	10-K	00
10.16.8	Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015.	10.17.8	10-K	00
10.17.1	ConocoPhillips Directors' Charitable Gift Program.	10.40	10-K	00
10.17.2	First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program.	10	10-Q	00
10.19.1	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated January 1, 2020.	10.19.1	10-K	00
10.19.2	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated January 1, 2020.	10.19.2	10-K	00
10.20	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014.	10.21	10-K	00
10.20.1*	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective December 2, 2021.			
10.22.1	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	00
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.	10.26	10-K	00
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.	10.27	10-K	00
10.23	Omnibus Amendments to certain ConocoPhillips employee benefit plans adopted December 7, 2007.	10.30	10-K	00

10.24	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	00
10.25.1	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	00
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.	10	10-Q	00
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.	10.26.6	10-K	00
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.	10.26.9	10-K	00
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.	10.2	10-Q	00
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.	10.1	10-Q	00
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.	10.26.12	10-K	00
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.	10.3	10-Q	00
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.	10.5	10-Q	00
10.25.17	Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014.	10.11	10-Q	00
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.	10.26.24	10-K	00
10.26.1	2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.1	8-K	00
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.	10.3	10-Q	00
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.	10.1	10-Q	00

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.	10.27.12	10-K	00
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.	10.27.14	10-K	00
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.	10.27.15	10-K	00
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.	10.27.16	10-K	00
10.27	Amended and Restated 409A Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated January 1, 2020.	10.27	10-K	00
10.29	Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012.	10.9	10-Q	00
10.30.1	Successor Trustee Agreement of the Deferred Compensation Trust Agreement for Non-Employee Directors of ConocoPhillips dated July 31, 2020.	10.1	10-Q	00
10.30.2	First Amendment to the Successor Trust Agreement of the Deferred Compensation Trust Agreement for Non-Employee Directors of ConocoPhillips, dated August 4, 2020.	10.2	10-Q	00
10.31	Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.1	8-K	00
10.32	Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.2	8-K	00
10.33	Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.3	8-K	00
10.34	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012.	10.4	8-K	00
10.36	ConocoPhillips Clawback Policy dated October 3, 2012.	10.3	10-Q	00
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.	10.1	8-K	00
10.38	Company Retirement Contribution Make-Up Plan of ConocoPhillips, dated December 28, 2018.	10.39	10-K	00
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.	10.1	10-Q	00
10.41	ConocoPhillips Executive Restricted Stock Unit Program, dated February 11, 2020.	10.1	10-Q	00

10.42	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.	10.1	10-Q	00
10.43	Form of Inducement Grant Award Agreement under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 15, 2021.	10.3	10-Q	00
10.44	Compensation Resolutions regarding Matthew J. Fox, dated April 8, 2021.	10.1	10-Q	00
10.45	Form of Aircraft Time Sharing Agreement by and between certain executives and ConocoPhillips dated June 21, 2021.	10.2	10-Q	00
10.46	Purchase and Sale Agreement, dated as of September 20, 2021, by and between Shell Enterprises LLC and ConocoPhillips.	10.1	10-Q	00
10.47*	Amendment and Restatement of ConocoPhillips Executive Severance Plan, dated December 2, 2021.			
21*	List of Subsidiaries of ConocoPhillips.			
22*	Subsidiary Guarantors of Guaranteed Securities.			
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. Co 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 exhib Rule 24b-2 under the Securities Exchange Act of 1934, as amended.*

Signature

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 193
has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized

CONOCOPHILLIPS

February 17, 2022

/s/ Ryan M. Lance
Ryan M. Lance
Chairman of the Board of Director
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been
February 17, 2022, on behalf of the registrant by the following officers in the capacity indicated and
directors.

Signature	Title
/s/ Ryan M. Lance Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ William L. Bullock, Jr. William L. Bullock, Jr.	Executive Vice President and Chief Financial Officer (Principal financial officer)
/s/ Kontessa S. Haynes-Welsh Kontessa S. Haynes-Welsh	Chief Accounting Officer (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/ Timothy A. Leach Timothy A. Leach	Director
/s/ William H. McRaven William H. McRaven	Director
/s/ Sharmila Mulligan Sharmila Mulligan	Director
/s/ Eric D. Mullins Eric D. Mullins	Director
/s/ Arjun N. Murti Arjun N. Murti	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ David T. Seaton David T. Seaton	Director
/s/ R.A. Walker R.A. Walker	Director

2020

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, 2020**

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 registere
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 [ ]

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]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securit 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 the registrant was required to submit such files). [x] Yes [ ]

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," "smal 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 [ ] Emergin growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period f 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b by the registered public accounting firm that prepared or issued its audit report. [x]

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 30, 2020, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $42.02, was $45.1 billion.

The registrant had 1,354,734,727 shares of common stock outstanding at January 31, 2021.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2021 (Part III)

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Commonly Used Abbreviations

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

Currencies

$ or USD	U.S. dollar
CAD	Canadian dollar
EUR	Euro
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
MBOD	thousand barrels of oil per day
MM	million
MMBOE	million barrels of oil equivalent
MMBOD	million barrels of oil per day
MBOED	thousands of barrels of oil equivalent per day
MMBOED	millions 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
G&G	geological and geophysical
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 obligatior
ASC	accounting standards codi
ASU	accounting standards upda
DD&A	depreciation, depletion an amortization
FASB	Financial Accounting Star Board
FIFO	first-in, first-out
G&A	general and administrativ
GAAP	generally accepted accour principles
LIFO	last-in, first-out
NPNS	normal purchase normal s
PP&E	properties, plants and equ
SAB	staff accounting bulletin
VIE	variable interest entity

Miscellaneous

EPA	Environmental Protection
ESG	Environmental, Social anc Corporate Governance
EU	European Union
FERC	Federal Energy Regulator Commission
GHG	greenhouse gas
HSE	health, safety and environ
ICC	International Chamber of Commerce
ICSID	World Bank's Internation Centre for Settlement of Investment Disputes
IRS	Internal Revenue Service
OTC	over-the-counter
NYSE	New York Stock Exchang
SEC	U.S. Securities and Excha 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 t 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 th 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 corre 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 disclosure under the headings “Risk Factors” beginning on page 23 and “CAUTIONARY STATEMENT FOR THE PURPOSES OF THE ‘SAFE HARBOR’ PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995,” beginning on page 75.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is an independent E&P company headquartered in Houston, Texas with operations and activities in 15 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe, and Asia; LNG developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. (December 31, 2020, we employed approximately 9,700 people worldwide and had total assets of $63 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.

On January 15, 2021, we completed the acquisition of Concho Resources Inc. (Concho), an independent oil and gas exploration and production company with operations in New Mexico and West Texas focused on th Permian Basin. For additional information related to this transaction, see Note 25—Acquisition of Concho Resources Inc., in the Notes to Consolidated Financial Statements.

SEGMENT AND GEOGRAPHIC INFORMATION

We manage our operations through six operating segments, defined by geographic region: Alaska; Lower 48 Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. Effective with the thi quarter of 2020, we restructured our segments to align with changes to our internal organization. The Middle East business was realigned from the Asia Pacific and Middle East segment to the Europe and North Africa segment. The segments have been renamed the Asia Pacific segment and the Europe, Middle East an North Africa segment. We have revised segment information disclosures and segment performance metrics presented within our results of operations for the current and prior years. For operating segment and geographic information, see Note 24—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwi basis. At December 31, 2020, our operations were producing in the U.S., Norway, Canada, Australia, 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 Operation disclosures following the Notes to Consolidated Financial Statements. Approximately 80 percent of our proved reserves are in countries that belong to the Organization for Economic Cooperation and Developmen 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 discussi 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	**2020**	2019	20
Crude oil			
Consolidated operations	**2,051**	2,562	2,5
Equity affiliates	**68**	73	
Total Crude Oil	**2,119**	2,635	2,6
Natural gas liquids			
Consolidated operations	**340**	361	3
Equity affiliates	**36**	39	
Total Natural Gas Liquids	**376**	400	3
Natural gas			
Consolidated operations	**1,011**	1,209	1,2
Equity affiliates	**621**	736	7
Total Natural Gas	**1,632**	1,945	2,0
Bitumen			
Consolidated operations	**332**	282	2
Total Bitumen	**332**	282	2
Total consolidated operations	**3,734**	4,414	4,3
Total equity affiliates	**725**	848	8
Total company	**4,459**	5,262	5,2

Total production, including Libya, of 1,127 MBOED decreased 221 MBOED or 16 percent in 2020 compare
with 2019, primarily due to:

- Normal field decline.
- The divestiture of our U.K. assets in the third quarter of 2019 and our Australia-West assets in the second quarter of 2020.
- Production curtailments of approximately 80 MBOED, primarily from North American operated assets and Malaysia.
- Lower production in Libya due to the forced shutdown of the Es Sider export terminal and other eastern export terminals after a period of civil unrest.

The decrease in production during 2020 was partly offset by:

- New wells online in the Lower 48, Canada, Norway, Alaska and China.

Production excluding Libya for 2020 was 1,118 MBOED. Adjusting for estimated curtailments of approximately 80 MBOED; closed acquisitions and dispositions; and excluding Libya, production for 2020 would have been 1,176 MBOED, a decrease of 15 MBOED compared with 2019 production. This decrease was primarily due to normal field decline, partly offset by new wells online in the Lower 48, Canada, Norwa
Alaska and China. Production from Libya averaged 9 MBOED as it was in force majeure during a significa
portion of the year.

Our worldwide annual average realized price decreased 34 percent from $48.78 per BOE in 2019 to $32.15 p
BOE in 2020 primarily due to lower realized crude oil, natural gas and bitumen prices. Our worldwide annu
average crude oil price decreased 35 percent, from $60.99 per barrel in 2019 to $39.54 per barrel in 2020. O
worldwide annual average natural gas price decreased 32 percent, from $5.03 per MCF in 2019 to $3.41 per
MCF in 2020. Average annual bitumen prices decreased 75 percent, from $31.72 per barrel in 2019 to $8.0
per barrel in 2020.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and NGL
We are the largest crude oil producer in Alaska and have major ownership interests in two of North America
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 1.3 million net undeveloped acres at year-end 2020. Alaska operations contributed 28 percent of our consolidated liquids production and 1 perce
of our consolidated natural gas production.

			2020			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production						
Greater Prudhoe Area	36.1 %	Hilcorp	68	16	4	
Greater Kuparuk Area	89.2-94.7	ConocoPhillips	74	-	2	
Western North Slope	100.0	ConocoPhillips	39	-	4	
Total Alaska			181	16	10	1

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Poi
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 recove

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.

In 2020, development activity included both rotary and coiled-tubing drilling through April, resulting in ten wells drilled and brought online. In response to the oil price collapse, the second half of 2020 saw a reductio in rig activity. Average net production increased from 81 MBOED in 2019 to 84 MBOED in 2020.

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 the Prudhoe Bay Field. Field installations include three central production facilities which separate oil, natural gas and water, as well as a seawater treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-laterals from existing well bores utilizing coiled-tubing drilling.

We operated both a rotary and a coiled-tubing drilling rig in the first half of 2020, resulting in seven operate wells drilled and brought online in 2020. In response to the oil price collapse, the second half of 2020 saw a reduction in rig activity. Average net production decreased from 86 MBOED in 2019 to 74 MBOED in 202

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. The Alpine Field is located 34 miles west of the Kuparuk Field. I 2020, an extended-reach drilling rig was delivered to the Alpine CD2 drillsite. This rig is North America's largest mobile land rig and is expected to commence drilling operations in 2021.

The Greater Mooses Tooth Unit is the first unit established entirely within the NPR-A. In 2017, we began construction in the unit with two drill sites; Greater Mooses Tooth #1 (GMT-1) and Greater Mooses Tooth # (GMT-2). GMT-1 achieved first oil in 2018 and completed drilling in 2019. In 2020, the second of three construction seasons for GMT-2 was completed and drilling operations are expected to commence in 2021 with first oil later in the year.

We operated both a rotary and a coiled-tubing drilling rig in the Western North Slope during 2020, resulting in five operated wells drilled and brought online. In response to the oil price collapse, the second half of 2020 saw a reduction in rig activity. Average net production decreased from 51 MBOED in 2019 to 40 MBOED in 2020.

Production Curtailments
In response to the oil price collapse that began in early 2020, we curtailed operated production—in the Grea Kuparuk Area and Western North Slope—by 8 MBOED in 2020. For more information related to the 2020 industry downturn and our response, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 potentia 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, however, AGDC decided to continue its own, focusing primarily on permitting efforts. Currently, AGDC is in the process of seeking new sponso for the project. Given current market conditions, we no longer believe the project will advance and since th is no current market, we recorded a before-tax impairment of $841 million for the entire associated carrying value of capitalized undeveloped leasehold costs and an equity method investment related to our Alaska Nor Slope Gas asset. We remain willing to sell our Alaska North Slope Gas to interested parties on a basis if a market materializes in the future. For additional information related to this impairment, See Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.

Exploration
Appraisal of the Willow Discovery in the Bear Tooth Unit in the National Petroleum Reserve-Alaska (NPR-A) continued with the drilling of two of four planned appraisal wells before the early cancellation of the 2020 program as part of our COVID-19 response. The reduced 2020 appraisal program consisted of drilling a horizontal well in the eastern portion of the field, informing the reservoir's connectivity, and a vertical well in the field's southern extent, reducing the original oil in place uncertainty. The initial development plan for the Willow Discovery, approved in the fourth quarter, does not include the Cassin Discovery from 2013; therefore, we recognized dry hole expense for two previously suspended Cassin wells in 2020.

In 2020, exploration of the Harpoon Complex—Harpoon, Lower Harpoon and West Harpoon—commenced. One exploration well of a planned three-well program was drilled before the early cancellation of our 2020 winter drilling season in response to COVID-19. The well was expensed as a dry hole after evaluations confirmed the well intersected sub-commercial volumes of hydrocarbons in the upper Harpoon interval which will not be developed. Future exploration plans include returning to the Harpoon Complex to explore the remaining potential.

In late 2018, we commenced appraisal of the Putu Discovery with a long-reach well from existing Alpine CD4 infrastructure. In 2019 and 2020 the long reach CD4 appraisal and supporting injector well finished drilling and testing. Production and injectivity tests confirmed development and waterflood feasibility of the reservoir. The project transitioned from appraisal to development in early 2020. Development planning is ongoing.

A 3-D seismic survey was completed in 2020 over a 234-mile area on state and federal lands. We are currently evaluating this seismic data for future exploration opportunities.

Transportation
We transport the petroleum liquids produced on the North Slope to Valdez, Alaska through an 800-mile pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.5 percent ownership interest in TAPS, and we also have ownership interests in and operate 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

On January 15, 2021, we completed the acquisition of Concho. This transaction significantly increases our Permian position by adding complementary acreage across the Delaware and Midland basins. The production and acreage figures and the property descriptions below do not reflect this recently closed acquisition. For additional information related to this acquisition, see Note 25—Acquisition of Concho Resources Inc., in the Notes to Consolidated Financial Statements.

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, at year-end 2020 we held 10.1 million net onshore and offshore acres, with a portfolio of low cost of supply, shorter cycle time, resource-rich unconventional plays, and conventional production from legacy assets. Based on 2020 production volumes, the Lower 48 is the company's largest segment and contributed 40 percent of our consolidated liquids production and 44 percent of our consolidated natural gas production.

			2020			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production						
Eagle Ford	Various %	Various	103	46	228	1
Gulf of Mexico	Various	Various	7	1	6	
Gulf Coast—Other	Various	Various	3	-	7	
Total Gulf Coast			113	47	241	1
Bakken	Various	Various	53	10	92	
Permian Unconventional	Various	Various	33	12	113	
Permian Conventional	Various	Various	12	2	42	
Anadarko Basin	Various	Various	1	3	50	
Wyoming/Uinta	Various	Various	-	-	44	
Niobrara*	Various	Various	1	-	3	
Total Great Plains			100	27	344	1
Total Lower 48			213	74	585	3

Disposed in March 2020. See Note 4—Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.

Onshore

At December 31, 2020, we held 10.1 million net acres of onshore conventional and unconventional acreage the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 1.3 million net acres in the following areas:

- 610,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 200,000 net acres in the Eagle Ford, located in South Texas.
- 170,000 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 300,000 net acres in other areas with unconventional potential.

In response to the oil price collapse that began in early 2020, we curtailed production in the Lower 48 by approximately 55 MBOED in 2020. For more information related to the 2020 industry downturn and our response, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. These production curtailments contributed to lower production in 2020 compared with 2019 fro our three focus areas:

- Eagle Ford—We operated five rigs on average in the Eagle Ford during 2020, resulting in 154 operated wells drilled and 71 operated wells brought online. Production decreased 14 percent in 20 compared with 2019, averaging 186 MBOED and 216 MBOED, respectively.
- Bakken—We operated an average of two rigs during the year in the Bakken and participated in additional development activities operated by co-venturers. We continued our pad drilling with 57 operated wells drilled during the year and 29 operated wells brought online. Production decreased 2 percent in 2020 compared with 2019, averaging 78 MBOED and 97 MBOED, respectively.
- Permian Basin—The Permian Basin is a combination of legacy conventional and unconventional assets. We operated one rig during the full year and another rig during parts of the year in the Perm Basin, resulting in 16 operated wells drilled and 16 operated wells brought online. Production decreased 1 percent in 2020 compared with 2019, averaging 85 MBOED and 86 MBOED, respectively.

Gulf of Mexico
At year-end 2020, 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 interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent interest in the Princess Field, a northern subsalt extension of the Ursa Field.
- 12.4 percent interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

Dispositions
In the first quarter of 2020, we completed the sale of our Waddell Ranch interests in the Permian Basin and Niobrara interests. Production from these dispositions was immaterial to the Lower 48 segment in 2020. Fo additional information on these transactions, see Note 4—Asset Acquisitions and Dispositions, in the Notes Consolidated Financial Statements.

Facilities

- Lost Cabin Gas Plant—We operate and own a 60 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 first half of 2021. The expected production loss in 2021 is immaterial to the segment.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facilit 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 Sugarloa Condensate Processing Facility, a 30 MBD condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processin Facility, a 15 MBD condensate processing plant located in Kenedy, Texas. This facility is currently being decommissioned.

CANADA

Our Canadian operations consist of the Surmont oil sands development in Alberta and the liquids-rich Montney unconventional play in British Columbia. In 2020, operations in Canada contributed 9 percent of c consolidated liquids production and 3 percent of our consolidated natural gas production.

	Interest		Operator	2020 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Bitumen MBD	Tot MBOE
Average Daily Net Production								
Surmont	50.0	%	ConocoPhillips	-	-	-	55	5
Montney	100.0		ConocoPhillips	6	2	40	-	1
Total Canada				6	2	40	55	7

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 ar pumped to the surface for further processing. We hold approximately 600,000 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. Surmon is a 50/50 joint venture with Total S.A. that offers long-lived, sustained production. We are focused on structurally lowering costs, reducing GHG intensity and optimizing asset performance.

In response to the oil price collapse that began in early 2020, we voluntarily curtailed production at Surmont by approximately 12 MBOED in 2020. For more information related to the 2020 industry downturn and our response, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Montney

In August 2020, we completed the acquisition of additional Montney acreage from Kelt Exploration. This acquisition consisted primarily of undeveloped properties, including 140,000 net acres in the liquids-rich Ing Fireweed asset Montney zone, which is directly adjacent to our existing Montney position. We now hold approximately 300,000 net acres in the Montney play with a 100 percent working interest. For additional information related to the Kelt Exploration acquisition, please see Note 4—Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Following the completion of third-party offtake facilities, our newly commissioned processing facility and production from our 2019 drilling program came online in February 2020. In 2020, development activity consisted of drilling 14 horizontal wells and completing 18 wells. Overall, 23 wells came online in 2020. In 2021, appraisal drilling and completions activity will continue to further explore the area's resource potentia

Exploration

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

EUROPE, MIDDLE EAST AND NORTH AFRICA

The Europe, Middle East and North Africa segment consists of operations principally located in the Norweg sector of the North Sea; the Norwegian Sea; Qatar; Libya; and commercial and terminalling operations in th U.K. In 2020, operations in Europe, Middle East and North Africa contributed 13 percent of our consolidate liquids production and 20 percent of our consolidated natural gas production.

Norway

			2020			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production						
Greater Ekofisk Area	30.7-35.1%	ConocoPhillips	46	2	39	
Heidrun	24.0	Equinor	12	1	32	
Aasta Hansteen	10.0	Equinor	-	-	82	
Troll	1.6	Equinor	2	-	54	
Alvheim	20.0	Aker BP	8	-	13	
Visund	9.1	Equinor	2	1	40	
Other	Various	Equinor	8	-	10	
Total Norway			78	4	270	1

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises four producing fields: Ekofisk, Eldfisk, Embla and Tor. The Tor II redevelopment achieved first production in December 2020. Crude oil is exported to Teesside, England, and the natural gas is export to Emden, Germany. The Ekofisk and Eldfisk fields consist of several production platforms and facilities, with development drilling continuing over the coming years.

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

Aasta Hansteen is a gas and condensate field located in the Norwegian Sea. 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.

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 fo storage and export via tankers. The natural gas is transported to a gas processing plant at Kollsnes, Norway, through the Gassled transportation system.

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

Exploration
A well we participated in during 2019, Canela, was expensed as a dry hole in 2020 after post drill analysis.

In 2020, we completed the third well of a three-well operated exploration campaign in Block 25/7 in the Nor Sea with the Hasselbaink Well. The Hasselbaink Well encountered insufficient hydrocarbons and was expensed as a dry hole in 2020. In the second half of 2020 we completed a two-well operated exploration campaign in the Norwegian Sea with the Warka and Slagugle wells. Both the Warka and Slagugle wells encountered hydrocarbons and will be evaluated for future appraisal programs.

We were awarded three new exploration licenses; PL1045, PL1047 and PL1064; and two acreage additions, PL917B and PL1009B. Additionally, we exchanged our interest in the PL938 exploration license for increased interest in the PL1047 exploration license.

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

Facilities
We operate and have a 40.25 percent ownership interest in an oil terminal at Teesside, England to support our Norway operations.

Qatar

			2020			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	T MBO
Average Daily Net Production						
QG3	30.0 %	Qatargas Operating Company Limited	13	8	371	
Total Qatar			13	8	371	

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 facilitie which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field ov a 25-year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LN 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.

Libya

	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To MBO
			2020			
Average Daily Net Production						
Waha Concession	16.3 %	Waha Oil Co.	8	-	5	
Total Libya			8	-	5	

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in th Sirte Basin. Our production operations in Libya and related oil exports have periodically been interrupted o the last several years due to the shutdown of the Es Sider crude oil export terminal. In 2020, we had five cru liftings from Es Sider, compared with 19 crude liftings from Es Sider in 2019. Production ceased in Februa 2020, due to a forced shutdown of the Es Sider export terminal and other eastern export terminals after a period of civil unrest. In October 2020, force majeure was lifted allowing production operations and related exports to resume.

ASIA PACIFIC

The Asia Pacific segment has exploration and production operations in China, Indonesia, Malaysia and Australia. In 2020, operations in the Asia Pacific segment contributed 10 percent of our consolidated liquid production and 32 percent of our consolidated natural gas production.

Australia

	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	T MBO
			2020			
Average Daily Net Production						
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	-	684	
Bayu-Undan*	56.9	ConocoPhillips	2	1	87	
Total Australia and Timor-Leste			2	1	771	

**This asset was disposed in May 2020. See Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements fo 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. Origi 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 2,800 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, 2020, APLNG has an outstanding balance of $6.2 billion on a $8.5 billion project finan facility. Project finance interest payments are bi-annual, concluding September 2030.

For additional information, see Note 5—Investments, Loans and Long-Term Receivables and Note 11—Guarantees, in the Notes to Consolidated Financial Statements.

Exploration
In 2019, we entered into an agreement with 3D Oil to acquire a 75 percent interest in and operatorship of an offshore Exploration Permit (T/49P) located in the Otway Basin, Australia. We obtained an additional five percent interest in 2020, increasing our interest to 80 percent. The required government approvals for the transfer of this interest were obtained in June 2020. We plan to conduct a 3-D seismic survey in the second half of 2021, subject to governmental approval of a recently submitted Environmental Plan.

Dispositions
In May 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations. These subsidiaries held a 37.5 percent interest in the Barossa Project and Caldita Field, a 56.9 percent interest in the Darwin LNG Facility and Bayu-Undan Field, and a 40 percent interest in the Greater Poseidon Fields. Production from the beginning of the year through the disposition date in May 2020 averag 43 MBOED. See Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.

Indonesia

			2020			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	MB
Average Daily Net Production						
South Sumatra	54 %	ConocoPhillips	2	-	290	
Total Indonesia			2	-	290	

During 2020, we operated two PSCs in Indonesia: the Corridor Block 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 i 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 yea after 2023 and retain a participating interest until 2043.

Exploration
We entered into the Central Kalimantan Kualakurun Block PSC in 2015 with an exploration period of six years. We completed the firm working commitment program in 2017, which included satellite mapping and 740-kilometer 2-D seismic acquisition program. After completion of prospect evaluation, both PSC contractors decided to relinquish rights and return this block to the government.

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	2020 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	To[tal] MBO[E]
Average Daily Net Production						
Penglai	49.0 %	CNOOC	30	-	-	
Total China			30	-	-	

Penglai
The Penglai 19-3, 19-9 and 25-6 fields are located in the Bohai Bay Block 11/05 and are in various stages development. Phase 1 and 2 include production from all three Penglai oil fields.

Wellhead Platform J Project in the Penglai 19-9 Field achieved first production in 2016. This project consisted of 62 wells that have all been completed and brought online as of December 2020.

The Phase 3 Project in the Penglai 19-3 and 19-9 fields consists of three new wellhead platforms and a cent processing platform. First production from Phase 3 was achieved in 2018 for two wellhead platforms and 2020 for the third wellhead platform. This project could include up to 186 wells, 91 of which have be completed and brought online as of December 2020.

The Phase 4A Project in the Penglai 25-6 Field consists of one new wellhead platform and achieved first production in December 2020. This project could include up to 62 new wells, two of which have been completed and brought online as of December 2020.

Panyu
We have a production license for Panyu 4-1 in Block 15/34. If a development occurs, our production licens for 15 years upon commencement of production.

Exploration
Exploration activities in the Bohai Penglai Field during 2020 consisted of two successful appraisal wells supporting future developments in the Bohai Bay Block 11/05.

We fulfilled our exploration well commitment in Panyu 4-1 in early 2020. No further exploration well operations are planned.

Malaysia

	Interest	Operator	2020 Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Tot[al] MBOE
Average Daily Net Production						
Gumusut	29.0 %	Shell	21	-	-	2
Malikai	35.0	Shell	11	-	-	1
Kebabangan (KBB)	30.0	KPOC	1	-	52	1
Siakap North-Petai	21.0	PTTEP	2	-	-	
Total Malaysia			35	-	52	4

We have varying stages of exploration, development and production activities across 1.5 million net acres in Malaysia, with working interests in five PSCs. Three of these PSCs are located in waters off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). We operate two exploration blocks, Block WL4-00 and SK304 in waters off the eastern Malaysian state of Sarawak.

Block J

Gumusut

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. Developmen drilling associated with Gumusut Phase 3 is planned to commence in the fourth quarter of 2021 with the firs of four planned wells. First oil is anticipated in 2022.

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. In 2020, we recognized dry hole expense and impaired the associated carrying value of unproved properties in the Kamunsu East Field that is no longer in our development plans.

KBB

During 2019, KBB tied-in to a nearby third-party floating LNG vessel which provided increased gas offtake capacity. Production from the field has been reduced since January 2020, due to the rupture of a third-party pipeline which carries gas production from KBB to market. The pipeline operator has initiated repairs with production expected to flow through the full length of the pipeline during 2021.

Block G

Malikai

We hold a 35 percent working interest in Malikai. This field achieved first production in December 2016 vi 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 six-well drilling campaign, commenced in 2020, with first oil anticipated in 2021.

Siakap North-Petai

We hold a 21 percent working interest in the unitized Siakap North-Petai (SNP) oil field. First oil from SNP Phase 2, a four-well program, is anticipated in the fourth quarter of 2021.

Production Curtailments

We experienced production curtailments of 4 MBOED in 2020.

Exploration

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. Further exploration drilling is planne for 2021.

In 2018, we were awarded a 50 percent working interest and operatorship of Block SK304 encompassing 2. million gross acres offshore Sarawak. We acquired 3-D seismic over the acreage and completed processing this data in 2019. Exploration drilling is planned for 2021.

In June 2020, we relinquished our 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block offshore Sarawak.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia and Argentina and contingenci associated with prior operations in other countries. As a result of our completed Concho acquisition on January 15, 2021, we refocused our exploration program and announced our intent to pursue a managed exit from certain areas.

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 an 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 acre 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, we filed two separate Force Majeure requests before the relevant authority for both blocks, which were granted. We have no immediate plans to perform under existing contracts, therefore, the Picoplata-1 Well was recorded to dry hole expense and we fully impaired the capitalized undeveloped leasehold costs associated with our Colombia assets during 2020.

Chile
In September 2020, we notified the operator of our decision to exit our 49 percent interest in the Coiron Bloc located in the Magallanes Basin in southern Chile. We are working with local authorities to finalize our withdrawal from this block.

Argentina
We have a 50 percent nonoperated interest in El Turbio Este Block, within the Austral Basin in southern Argentina. Following the acquisition and processing of 3-D seismic covering approximately 500 square mil in 2019, planned activities in 2020 were delayed due to the impact of COVID-19 and force majeure in the block.

We have a 50 percent non-operated interest in the Bandurria Norte and Aguada Federal blocks within the Neuquen Basin in central Argentina. Following a successful production test of two horizontal wells on the Aguada Federal Block, we increased our interest from 45 to 50 percent in April 2020 where two horizontal wells continued production testing throughout the year. Preparation for a 2021 work program is ongoing.

Venezuela and Ecuador
For discussion of our contingencies in Venezuela and Ecuador, see Note 12—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 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 indic 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 syste meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containme system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico.

OSRL Subsea Well Intervention Service (SWIS)
OSRL-SWIS is a non-profit organization in the U.K. that is an industry funded joint initiative providing the capability to respond to subsea well-control incidents. Through our SWIS subscription, ConocoPhillips has access to equipment that is maintained and stored in a response ready state. This 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 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. North America, our primary OSROs include the Marine Spill Response Corporation for the continental U. S 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 includi 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, produc heavy oil economically with less emissions, improve the efficiency of our exploration program, increase recoveries from our legacy fields, and implement sustainability measures.

We are the second largest LNG liquefaction technology provider globally. Our Optimized Cascade® LNG liquefaction technology has been licensed for use in 27 LNG trains around the world, with feasibility studies ongoing for additional trains and four new products announced in 2020 that expand the scope of LNG licensing.

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, 2020. No difference exists between our estimated total proved reserve for year-end 2019 and year-end 2018, which are shown in this filing, and estimates of these reserves shown i a filing with another federal agency in 2020.

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 th 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 and 156 million barrels of crude oil in the futur These contracts have various expiration dates through the year 2030. We expect to fulfill these commitments with third-party purchases, as supported by our gas management agreements; proved develope reserves; and PUDs. 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 singl 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-effectiv manner. Based on statistics published in the September 7, 2020, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids production and reserves and one of the to ten U.S. companies measured by worldwide natural gas production and reserves in 2019. 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.

HUMAN CAPITAL MANAGEMENT

Values, Principles and Governance

At ConocoPhillips, our human capital management approach is anchored to our core SPIRIT Values. Our SPIRIT Values – Safety, People, Integrity, Responsibility, Innovation, and Teamwork – set the tone for how we interact with all our stakeholders, internally and externally. In particular, we believe a safe organization i successful organization, so we prioritize personal and process safety across the company. Our SPIRIT Value are a source of pride. Our day-to-day work is guided by the principles of accountability and performance, which means the way we do our work is as important as the results we deliver. We believe these core values and principles set us apart, align our workforce and provide a foundation for our culture.

Our Executive Leadership Team (ELT) and our Board of Directors play a key role in setting our human capi management philosophies and tracking our progress. The ELT and Board of Directors engage often on workforce-related topics. Our human capital management programs are overseen and administered by our human resources function with support from business leaders across the company.

We depend on our workforce to successfully execute our company’s strategy and we recognize the importance of creating a workplace in which our people feel valued. We take a broad view of human capital management that begins with offering a compelling culture and includes programs and processes necessary for ensuring w have an engaged workforce with the skills to meet our business needs. The key elements of our human capit management are described below.

COVID-19 Response

In 2020, a significant effort was undertaken to address the ongoing COVID-19 pandemic. In the very early stages of the pandemic, we adopted and embraced three company-wide priorities to guide our activities in th midst of COVID-19: to protect our employees, mitigate the spread of COVID-19 and safely run the busines We have pursued these priorities via a coordinated crisis management support team, frequent workforce communications and flexible programs to suit the challenging environment. We transitioned to a remote work environment for periods of time to ensure the safety of our employees, partners and the community, and the implemented rigorous cleaning and disinfecting processes and rigorous mitigation protocols to keep our workforce safe, including temperature scans, social distancing, face covering requirements and increased sanitation as employees returned to the office setting.

Culture of Feedback and Engagement

Our human capital management approach recognizes that a compelling culture and an engaged workforce ar powerful determinants of business success. Beginning in 2019, we launched a coordinated, multi-year, glob employee feedback program called “Perspectives.” In mid-2019 we administered our first Perspectives surv which received an 86 percent employee response rate and yielded more than 35,000 comments. We achieved an employee satisfaction score that, on a 100-point scale, was 5 points higher than general industry and 11 points higher than our energy peers who used the same platform. Importantly, the quantitative and qualitativ survey data were used by leaders across the company to identify and analyze relative strengths and gaps and develop action plans to address gaps.

We intended to repeat the comprehensive Perspectives survey in 2020; however, in light of the COVID-19 pandemic and the significant industry downturn, we elected to defer the full survey until 2021 and instead focused our 2020 feedback program on the specific topic of Diversity and Inclusion (D&I). The “Perspectives Pulse: D&I” survey also received a high response rate with over 10,000 comments. The ELT and an internal D&I Council are responsible for analyzing the survey data to identify D&I strengths and gaps, and t use the findings to establish 2021 D&I priorities and action plans. The company’s D&I commitment, activities and programs are described below.

Diversity and Inclusion

Our commitment to D&I is foundational to our SPIRIT Values and our stated company-wide D&I goal is to have “a diverse culture of belonging where everyone feels valued.” We believe a diverse workforce and an inclusive environment that reflects different backgrounds, experiences, ideas and perspectives drives innovation, employee satisfaction and overall company performance. We hold our entire workforce accountable for creating and sustaining an inclusive work environment. Our leaders are accountable for having personal D&I goals each year and we believe senior leadership involvement is critical for achieving meaningful progress on D&I.

The ELT has ultimate accountability for advancing our D&I commitment through a governance structure tha includes an ELT-level D&I Champion, a global D&I Council consisting of senior leaders from across the company and organization-wide D&I goals. Leaders meet regularly with each other and with the workforce discuss challenges, opportunities, best practices and progress. In addition, our D&I plans and progress are reviewed regularly with the Board of Directors.

In 2018, the company established three pillars to guide our D&I activities: leadership accountability, employ awareness, and processes and programs. Since then, we have established corporate priorities annually under each of these areas. In 2020 we also published our first D&I Annual Report internally and we expect to update this report periodically as an important part of holding ourselves accountable for progressing our D&I goals throughout ConocoPhillips. Some of our key D&I actions and accomplishments over the past few years include:

- Publishing our first D&I Dashboards internally which contain key D&I statistics for our global and U.S. employees at year-end for the periods 2015-2019;
- Launching a company-wide platform for our workforce to talk openly about D&I;
- Expanding our workforce recognition programs to include a prestigious “SPIRIT Award” for D&I advocates;
- Implementing a “how rating” and an upward feedback process as part of our performance management system to hold our workforce and our leaders accountable for D&I;
- Broadening our D&I-related training resources; and
- Advocating for broad participation in, and awareness of our extensive network of employee resourc groups, which drew participation from over 5,000 people in 2020.

We recognize that achieving our D&I goals require the visible actions described above, but also requires a clear linkage to the daily activities of our workforce. These activities include:

- Educating managers on inclusive hiring practices;
- Conducting immersive D&I training for senior leaders and influencers;
- Examining our Talent Management Teams' processes to eradicate bias within our selection and succession efforts;
- Working with partners to connect veterans and individuals with disabilities with employment;
- Promoting inclusion of employees with disabilities through a robust accommodation process available to all employees;
- Ensuring diverse internal and external candidate slates; and
- Creating balanced interview teams to mitigate any unconscious bias in our hiring processes.

We actively monitor diversity metrics on a global basis. In addition to our internal dashboards, we publicly report our representation of women and minorities in leadership roles. We have also committed to publicly disclose ConocoPhillips' Consolidated EEO-1 Report effective upon our next submission to the U.S. Equal Employment Opportunity Commission in 2021. Tables of 2020 employee demographics by gender and ethnicity, and by country, are shown below:

2020 Employees by Gender* and Ethnicity

	Male	Female	Non-POC**	POC
All Employees	73 %	27%	75 %	25 %
All Leadership	77	23	81	19
Top Leadership	81	19	87	13
Junior Leadership	76	24	78	22

**While we present male and female, we acknowledge this is not fully encompassing of all gender identities.*
***"POC" refers to People of Color or racial and ethnic minorities self-reported in the U.S.*
Note: percentages based on year-end 2020 employee count of 9,700.

2020 Employees by Country	**Percent of Total**
USA	59 %
Norway	19
Canada	8
Indonesia	6
Great Britain	3
Australia	3
China	1
Other Global Locations	1
	100

Our human capital management approach addresses programs and processes necessary for ensuring an engaged workforce with the skills to meet our business needs. We take a holistic view of human capital management that addresses each of the critical components of workforce planning. These are described in more detail below.

Hiring & Retention

Our success depends on having the right workforce to meet our business needs. Attracting and retaining a skilled, engaged and diverse workforce is a top priority. We conduct routine personnel needs assessments leaders to ensure we have the organizational capacity and capabilities to execute our business plans. We've taken significant steps to embed inclusion into each step of our recruiting practices, including adapting the w we construct job descriptions to using intentionally diverse interview panels. To attract qualified, diverse candidates for full-time positions or internships, we recruit from a number of universities in the U.S. By attending conferences and recruiting at Hispanic-serving institutions and historically black colleges and universities, we have extended a broader outreach to potential diverse candidates.

We closely monitor recruitment metrics through our university dashboards in areas such as gender, ethnicity and university acceptance rates to help guide decisions and best practices. These are disclosed internally through our D&I Dashboards to ensure greater transparency. In addition, voluntary turnover metrics are routinely tracked and disclosed to guide our retention activities, as necessary.

2020 Hiring & Retention Metrics (U.S.)	Percent of Total
University hire acceptance	85
Interns acceptance	74
Diversity hiring - Women	29
Diversity hiring - POC	28
Total voluntary attrition	3

Talent Development

We employ a comprehensive approach for ensuring our workforce is adequately prepared for their responsibilities and also to advance their career. Our workforce is trained through a combination of on-the-j learning, formal training, regular feedback and mentoring. Skill-based Talent Management Teams (TMTs) guide employee development and career progression by skills and location. The TMTs help identify our futu business needs and assess the availability of critical skill sets within the company. We use a performance management program focused on objectivity, credibility and transparency. The program includes broad stakeholder feedback, real-time recognition and a formal rating to assess behaviors to ensure they are in line with our SPIRIT values.

ConocoPhillips has established core leadership competencies that provide a common baseline of knowledge, skills, abilities, and behaviors to support employee performance, growth, and success. All supervisors have access to a voluntary 360-feedback tool to receive feedback on their strengths and opportunities relative to these competencies. We offer training on a broad range of technical and professional skills, from data analytics to communication skills.

Compensation, Benefits and Well-Being

We offer competitive, performance-based compensation packages and have global equitable pay practices. Our compensation programs are generally comprised of a base pay rate, the annual Variable Cash Incentive Program (VCIP) and, for eligible employees, the Restricted Stock Unit (RSU) program. From the CEO to th frontline worker, every employee participates in VCIP, our annual incentive program, which aligns employe compensation with ConocoPhillips' success on critical performance metrics and also recognizes individual performance. Our RSU program is designed to attract and retain employees, reward performance, and align employee interest with stockholders by encouraging stock ownership. Our retirement and savings plans are intended to support employee's financial futures and are competitive within local markets.

We routinely benchmark our global compensation and benefits programs to ensure they are competitive, inclusive, aligned with company culture, and allow our employees to meet their individual needs and the nee of their families. We provide flexible work schedules and competitive time off, including parental leave policies in many locations. In 2020, our U.S. parental leave benefit increased from two weeks to six weeks and combined with our maternity benefit (eight weeks), new birth mothers are eligible for up to 14 weeks of paid leave.

Our global wellness programs include biometric screenings and fitness challenges designed to educate and promote a healthy lifestyle. All employees have access to our employee assistance program, and many of ou locations offer custom programs to support mental well-being.

Compensation Risk Mitigation

ConocoPhillips has considered the risks associated with each of its executive and broad-based compensatior programs and policies. As part of the analysis, we considered the performance measures we use, as well as t different types of compensation, varied performance measurement periods, and extended vesting schedules utilized under each incentive compensation program. As a result of this review, management concluded the risks arising from our compensation policies and practices are not reasonably likely to have a material adver effect on ConocoPhillips. As part of the Board of Directors' oversight of ConocoPhillips' risk management programs, the Human Resources Compensation Committee (HRCC) conducts a similar review with the assistance of its independent compensation consultant. The HRCC agrees with management's conclusion that risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on ConocoPhillips.

GENERAL

At the end of 2020, we held a total of 1,038 active patents in 50 countries worldwide, including 419 active U.S. patents. During 2020, we received 65 patents in the U.S. and 69 foreign patents. Our products and processes generated licensing revenues of $16 million related to activity in 2020. 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 goa 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 tracke 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 64 through 69 under the captions "Environmental" and "Climate Change is incorporated herein by reference. It includes information on expensed and capitalized environmental cost for 2020 and those expected for 2021 and 2022.

Website Access to SEC Reports

Our internet website address is *www.conocophillips.com*. Information contained on our internet website is n 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 or other risks that are yet unknown were to occur, our business, operating results and financial condition, as well as the value of an investment in our common stock could be adversel affected.

Risks Related to Our Industry

We have been negatively affected and may continue to be negatively affected by the prolonged drop in commodity prices that began in early 2020.

The oil and gas business is fundamentally a commodity business and our revenues, operating results and futu rate of growth are highly dependent on the prices we receive for crude oil, bitumen, natural gas, NGLs and LNG. Such prices can fluctuate widely depending upon global events or conditions that affect supply and demand, most of which are out of our control. Since early 2020, there has been a precipitous decrease in demand for oil globally, largely caused by the dramatic decrease in travel and commerce resulting from the COVID-19 pandemic. See Item 7. Management's Discussion and Analysis of Financial Condition and Resu of Operations, for additional information on commodity prices and how we have been impacted. There is no assurance of when or if commodity prices will return to pre-COVID-19 levels, and if they do return to pre-COVID levels, how long they will remain at those levels. The speed and extent of any recovery remains uncertain and is subject to various risk factors, including the duration, impact and actions taken to stem the proliferation of the COVID-19 pandemic, the extent to which those nations party to the OPEC plus producti agreement decide to increase production of crude oil, bitumen, natural gas and NGLs and other factors described herein. Even after a recovery, our industry will continue to be exposed to the effects of changing commodity prices given the volatility in commodity price drivers and the worldwide political and economic environment generally, as well as continued uncertainty caused by armed hostilities in various oil-producing regions around the globe.

Lower crude oil, bitumen, natural gas, NGL and LNG prices may have a material adverse effect on our revenues, earnings, cash flows and liquidity, and may also affect the amount of dividends we elect to declar and pay on our common stock. As a result of the oil market downturn that began in early 2020, we suspend our share repurchase program. Lower prices may also limit the amount of reserves we can produce economically, thus adversely affecting our proved reserves and reserve replacement ratio and accelerating th reduction in our existing reserve levels as we continue production from upstream fields. Prolonged depresse crude oil prices may affect certain decisions related to our operations, including decisions to reduce capital investments or curtail operated production.

Significant reductions in crude oil, bitumen, natural gas, NGLs and LNG prices could also require us to redu our capital expenditures, impair the carrying value of our assets or discontinue the classification of certain assets as proved reserves. In 2020, we recognized several impairments, which are described in Note 7—Suspended Wells and Exploration Expenses and Note 8—Impairments, in the Notes to Consolidated Financi Statements, due to changes in assumptions for commodity prices and development plans. If the outlook for commodity prices remains low relative to historic levels, and as we continue to optimize our investments an exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used i operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. If oil and gas prices persist at depressed levels, our reserve estimates may decrease further, whic could incrementally increase the rate used to determine DD&A expense on our unit-of-production method properties. See Item 7. Management's Discussion and Analysis for further examination of DD&A rate impa versus comparative periods. Although it is not reasonably practicable to quantify the impact of any future impairments or estimated change to our unit-of-production rates at this time, our results of operations could l adversely affected as a result.

Our business has been, and will continue to be, adversely affected by the coronavirus (COVID-19) pandemic.

The COVID-19 pandemic and the measures put in place to address it have negatively impacted the global economy, disrupted global supply chains, reduced global demand for oil and gas, and created significant volatility and disruption of financial and commodity markets. According to the National Bureau of Economic Research, as a result of the pandemic and its broad reach across the entire economy, the U.S. entered a recession in early 2020 and the timing, pace and extent of the recovery is still unknown. Public health offici have recommended or mandated certain precautions to mitigate the spread of COVID-19, including limiting non-essential gatherings of people, ceasing all non-essential travel and issuing "social or physical distancing guidelines, "shelter-in-place" orders and mandatory closures or reductions in capacity for non-essential businesses. Although some of these limitations and mandates have been relaxed in certain jurisdictions, oth have been reinstated in areas that have experienced a resurgence of COVID-19 cases. In addition, despite approval of vaccines to immunize against COVID-19, the speed at which such vaccinations will be available the public, the public's willingness to be inoculated and the effectiveness of the vaccine (including to varian still remain unknown. As a result, the full impact of the COVID-19 pandemic remains uncertain and will depend on the severity, location and duration of the effects and spread of the disease, the effectiveness and duration of actions taken by authorities to contain the virus or treat its effect, the availability and effectivene of vaccines or other treatments, and how quickly and to what extent economic conditions improve.

We have already been impacted by the COVID-19 pandemic. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, for additional information on how we have been impacted and the steps we have taken in response.

Our business is likely to continue to be further negatively impacted by the COVID-19 pandemic. These impacts could include but are not limited to:

- Continued reduced demand for our products as a result of prolonged reductions in travel and commerce, even if restrictions are lifted;
- Disruptions in our supply chain due in part to scrutiny or embargoing of shipments from infected ar or invocation of force majeure clauses in commercial contracts due to restrictions imposed as a resu of the global response to the pandemic;
- Failure of third parties on which we rely, including our suppliers, contract manufacturers, contracto joint venture partners and external business partners, to meet their obligations to the company, or significant disruptions in their ability to do so, which may be caused by their own financial or operational difficulties or restrictions imposed in response to the disease outbreak;
- Reduced workforce productivity caused by, but not limited to, illness, travel restrictions, quarantine or government mandates;
- Business interruptions resulting from a portion of our workforce continuing to telecommute, as well the implementation and maintenance of protections for employees commuting for work, such as personnel screenings and self-quarantines before or after travel; and
- Voluntary or involuntary curtailments to support oil prices or alleviate storage shortages for our products.

Any of these factors, or other cascading effects of the COVID-19 pandemic that are not currently foreseeabl could materially increase our costs, negatively impact our revenues and damage our financial condition, resu of operations, cash flows and liquidity position. Despite the rollout of vaccines, the pandemic continues to progress and evolve, and the full extent and duration of any such impacts cannot be predicted at this time because of the sweeping impact of the COVID-19 pandemic on daily life around the world and a lack of certainty as to if or when conditions will return to pre-COVID levels.

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 conduc successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline material as we produce crude oil, bitumen, natural gas and NGLs, and our business will experience reduced cash flov 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 busines 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 crude oil, bitumen, natural ga 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. In addition, we may be at a competitive disadvantage when competing with stat owned companies if they are motivated by political or other factors in making their business decisions, with less emphasis on financial returns. If we are not successful in our competition for new reserves, our financi condition and results of operations may be adversely affected.

Any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natu 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 base 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 prope associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation.

Our business may be adversely affected by price controls, government-imposed limitations on production 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, bitum natural gas and NGLs.

As discussed herein, 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 crude oil, bitumen, natural gas and NGL wells below actual production capacity. Because legal requiremen 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 an pipeline facilities and equipment, as well as any necessary diluents to prepare our crude oil, bitumen, natura 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 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 fr 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 w 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 obligation 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.

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 operation 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 t 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 equipmen 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 no 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.

Legal and Regulatory Risks

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, whic are expected to continue to have an increasing impact on our operations. For a description of the most significant of these environmental laws and regulations, see the “Contingencies—Environmental” and “Contingencies—Climate Change” sections of Management’s Discussion and Analysis of Financial Conditi 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, including those issued by national, subnational, and local authorities;
- The discharge of pollutants into the environment;
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and GHG emission
- Carbon taxes;
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardo and nonhazardous wastes;
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives; and
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, c 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, othe 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 o operations and cash flows in future periods could be materially adversely affected.

Existing and future laws, regulations and internal 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 ar 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 efficienc standards and incentives or mandates for renewable energy. For example, in December 2015, the U.S. joine 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 ar represent a progression in their intended GHG emission reduction goals every five years beginning in 2020. While the U.S. previously withdrew from the Paris Agreement, the new administration has recommitted the United States to the Paris Agreement, and a significant number of U.S. state and local governments and majo corporations headquartered in the U.S. have also announced their intention to satisfy these commitments. In addition, our operations continue in countries around the world which are party to, and have not announced a 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, maintenar and remediation costs, any of which may have an adverse effect on our business and results of operations.

In October 2020, we announced the adoption of a Paris-aligned climate risk framework, whereby we committed to a reduction of our gross operated (scope 1 and 2) emissions intensity, with an ambition to achieve net zero by 2050 from operated emissions. We also endorsed the World Bank Zero Routine Flaring by 2030 initiative, with an ambition to meet that goal by 2025 and reaffirmed our commitment to advocate for reduction of scope 3 emissions intensity through our support for a U.S. carbon price. Compliance with, and achievement of, climate change related internal initiatives such as the foregoing may increase costs, require to purchase emission credits, or limit or impact our business plans, potentially resulting in the reduction to th economic end-of-field life of certain assets and an impairment of the associated net book value.

Increasing attention to global climate change has also resulted in pressure upon stockholders, 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. For example, in 2019 Norway's Government Pension Fund announced it would reduce its investment exposure to companies that explore for oil and gas, and in 2020 a number of major financial institutions announced that they would no longer finance oil and gas exploration projects in the Arctic. As public pressure continues to mount, our access to capital on terms we find favorab (if it is available at all) may be limited and our costs may increase or our business and results of operations may be otherwise adversely affected.

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 aff our business. Beginning in 2017, cities, counties, governments and other entities in several states in the U.S have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. Additional lawsuits with similar allegations are expected to be filed. The amounts claimed by plaintiffs are unspecified and the legal and factual issues involved in these cases are unprecedented. ConocoPhillips believes these lawsuits are factually and legally meritless and are an inappropriate vehicle to address the challenges associated with climate change and will vigorously defend against such 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 t 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 th 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 material 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, 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 to violate non-disclosure laws of other countries have been imposed or proposed by governments or certain interest groups. For example, in 2020 a ballot initiative known as the Fair Share Act was proposed in the sta of Alaska, which, if enacted would have increased the state's share of production revenues and required producers to publicly disclose additional financial information. Although ultimately defeated, similar initiatives may be proposed and may be successful in the future. The change in control of Congress and the White House because of the 2020 election increases the possibility of the promulgation of more stringent regulations of our operations and the enactment of tax law changes that may adversely affect the fossil fuel industry. In addition, the current administration may use the Congressional Review Act to repeal the regulations finalized in the last five months of the prior administration. We also cannot rule out the possibility of similar regulatory shifts and attendant cost and market access implications in other international jurisdictions.

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 permeabili rock formations. A range of local, state, federal and national laws and regulations currently govern or, in so hydraulic fracturing operations, prohibit hydraulic fracturing in some jurisdictions. Although hydraulic fracturing has been conducted safely for many decades, a number of new laws, regulations and permitting requirements are under consideration which could result in increased costs, operating restrictions, operationa delays or could limit the ability to develop oil and natural gas resources. Certain jurisdictions in which we operate 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. On January 27, 2021, the new administration signed an executive orde directing the Secretary of the Interior to stop issuing new oil and gas leases on federal lands, allowing time t review and reset the Federal Government's oil and gas leasing program. Existing production and permits already issued on Federal lands were not impacted by this order. If this temporary moratorium were to be extended indefinitely, we believe we can mitigate the impact for a considerable period of time with our curre permits and adjusting our development plans across our diverse acreage position.

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. In the event that ballot initiatives, local, state, or national 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 complian costs and delays, curtailments, limitations or prohibitions could have a material adverse effect on our busine 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 asse by the Venezuelan government, have affected operations significantly in the past and may continue to do so the future. Changes in domestic and international policies and regulations may affect our ability to collect payments such as those pertaining to the settlement with PDVSA or the ICSID Award against the Governme of Venezuela; or to obtain or maintain permits, including those necessary for drilling and development of we in various locations. Similarly, the declaration of a "climate emergency" could result in actions to limit exports of our products and other restrictions.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 48 percent of our hydrocarbon production was derived from production outside the U.S. in 2020, and 42 percent of our proved reserves, as of December 31, 2020, were located outside the U.S. We are subject to risks associated with operations in international markets, including changes in foreign governmen policies relating to crude oil, natural gas, bitumen, NGLs or LNG pricing and taxation, other political, economic or diplomatic developments (including the macro effects of international trade policies and disputes), potentially disruptive geopolitical 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 increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increase risks of adverse actions by local government authorities, such as expropriations.

Risks Related to Our Acquisition of Concho

Combining our business with Concho's may be more difficult, costly or time-consuming than expected an we may fail to realize the anticipated benefits of the Merger, which may adversely affect our business resu and negatively affect the value of our common stock.

Our acquisition of Concho (the Merger) involved the combination of two companies which, until the completion of the Merger, operated as independent public companies. The success of the Merger will depend on, among other things, the ability of our two companies to combine our businesses in a manner that adds value to shareholders. However, there can be no assurances that our respective businesses can be integrated successfully, and we will be required to devote significant management attention and resources to the integration process. We must achieve the anticipated improvement in free cash flow generation and returns and achieve the planned cost savings without adversely affecting current revenues or compromising the disciplined investment philosophy to maximize value for shareholders.

There are a large number of processes, policies, procedures, operations and technologies and systems that m be integrated, and although we expect that the elimination of duplicative costs, strategic benefits, and additional income, as well as the realization of other efficiencies related to the integration of the business, m offset incremental transaction and Merger-related costs over time, we may encounter difficulties in the integration and any net benefit may not be achieved in the near term or at all. It is possible that the integrati process could take longer than originally anticipated and could result in the loss of key employees; the loss c commercial and vendor partners; the disruption of our ongoing businesses; inconsistencies in standards, controls, procedures and policies; unexpected integration issues; and higher than expected integration costs.

An inability to realize the full extent of the anticipated benefits of the Merger and the other transactions contemplated by the Merger Agreement, as well as any delays encountered in the integration process, could have an adverse effect upon the revenues, level of expenses and operating results of ConocoPhillips, which may adversely affect the value of our common stock.

The market value of our common stock could decline if large amounts of our common stock are sold now that the Concho acquisition has been consummated.

We issued shares of ConocoPhillips common stock to former Concho stockholders. Former Concho stockholders may decide not to hold the shares of ConocoPhillips common stock that they received in the Merger, and ConocoPhillips stockholders may decide to reduce their investment in ConocoPhillips as a resu of the changes to ConocoPhillips' investment profile as a result of the Merger. Other Concho stockholders, such as funds with limitations on their permitted holdings of stock in individual issuers, may be required to s the shares of ConocoPhillips common stock that they received in the Merger. Such sales of ConocoPhillips common stock could have the effect of depressing the market price for ConocoPhillips common stock.

Other Risk Factors Facing our Business or Operations

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

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 or 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 ab to do so. Our ability to obtain additional financing or refinance our existing indebtedness when it matures o 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 downgrad 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 i 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 liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry 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 counterpartie 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 resul 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 a arbitration award issued by the International Chamber of Commerce (ICC) Tribunal in favor of ConocoPhill on a contractual dispute arising from Venezuela's expropriation of our interests in the Petrozuata and Hama heavy oil ventures and other pre-expropriation fiscal measures. We have collected approximately $0.8 of the $2.0 billion settlement to date and PDVSA has defaulted on its remaining payment obligations under this agreement. We are therefore incurring additional costs as we seek to recover any unpaid amounts under the agreement. Additionally, in March 2019, an ICSID arbitration tribunal issued an award unanimously ordering the government of Venezuela to pay ConocoPhillips approximately $8.7 billion in compensation fo the government's unlawful expropriation of the company's investments in Venezuela in 2007. ConocoPhilli has filed requests for recognition of the award in several jurisdictions. On August 29, 2019, the ICSID tribu 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 is seeking annulment of the award before another panel at ICSID and annulment proceedings are underway. No amounts have been collected as a result of thi award yet.

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 propertie
- The level of distributions paid by comparable companies;
- Our operating expenses; and
- 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 p our desired levels of dividends to our stockholders or to pay dividends to our stockholders at all.

Additionally, as of December 31, 2020, $14.5 billion of repurchase authority remained of the $25 billion sha repurchase program our Board of Directors had authorized. Our share repurchase program does not obligate to acquire a specific number of shares during any period, and our decision to commence, discontinue or resu repurchases in any period will depend on the same factors that our Board of Directors may consider when declaring dividends, among others. In the past we have suspended our share repurchase program in respons to market downturns, and we may do so again in the future.

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 comm stock.

There are substantial risks with any acquisitions or divestitures we may choose to undertake.

We regularly review our portfolio and pursue growth through acquisitions and seek to divest non-core assets businesses. We may not be able to complete these transactions on favorable terms, on a timely basis, or at a Even if we do complete such transactions, our cash flow from operations may be adversely impacted or otherwise the transactions may not result in the benefits anticipated due to various risks, including, but not limited to (i) the failure of the acquired assets or businesses to meet or exceed expected returns, including ris of impairment; (ii) difficulties in integrating the operations, technologies, products and personnel of the acquired assets or businesses; (iii) the inability to dispose of non-core assets and businesses on satisfactory terms and conditions; and (iv) the discovery of unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections are inadequate or we lack insurance or indemnities, includi environmental liabilities, or with regard to divested assets or businesses, claims by purchasers to whom we have provided contractual indemnification.

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 colle 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-parti with whom we do business and attempted cyber terrorism.

In addition, computers control oil and gas production, processing equipment and distribution systems global 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 o 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 contr 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 ar 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 counterpa 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, 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. 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 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 ar 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.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Name	Position Held	A
Catherine A. Brooks	Vice President and Controller	5
William L. Bullock, Jr.	Executive Vice President and Chief Financial Officer	5
Ellen R. DeSanctis	Senior Vice President, Corporate Relations	6
Matt J. Fox	Executive Vice President and Chief Operating Officer	6
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	5
Timothy A. Leach	Executive Vice President, Lower 48	6
Andrew D. Lundquist	Senior Vice President, Government Affairs	6
Dominic E. Macklon	Senior Vice President, Strategy, Exploration and Technology	5
Nicholas G. Olds	Senior Vice President, Global Operations	5
Kelly B. Rose	Senior Vice President, Legal, General Counsel	5

**On February 16, 2021.*

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 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 11, 2021. Set forth below is information about the executive officers.

Catherine A. Brooks was appointed Vice President and Controller as of January 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 Executive Vice President and Chief Financial Officer as of Septemb 2020, having previously served as President, Asia Pacific & Middle East since April 2015. Prior to that, he was Vice President, Corporate Planning & Development since May 2012.

Ellen R. DeSanctis was appointed Senior Vice President, Corporate Relations as of January 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 2019, havin previously served as Executive Vice President, Strategy, Exploration and Technology since March 2016 and Executive Vice President, Exploration and Production, from May 2012 to March 2016. Prior to that, he was employed by Nexen, Inc., where he served as Executive Vice President, International since 2010.

Ryan M. Lance was appointed Chairman of the Board of Directors and Chief Executive Officer in May 201 having previously served as Senior Vice President, Exploration and Production—International since May 2009.

Timothy A. Leach was appointed Executive Vice President, Lower 48 in January 2021. Prior to joining ConocoPhillips, Mr. Leach served as Chairman and Chief Executive Officer of Concho Resources Inc., from its formation in February 2006, until its acquisition by ConocoPhillips in January 2021.

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

Dominic E. Macklon was appointed Senior Vice President, Strategy, Exploration and Technology as of August 2020, having previously served as President, Lower 48 since June 2018. Prior to that, he served as Vice President, Corporate Planning & Development since January 2017 and President, U.K. from Septembe 2015 to January 2017. Mr. Macklon previously served as Senior Vice President, Oil Sands in Canada from July 2012 to September 2015.

Nicholas G. Olds was appointed Senior Vice President, Global Operations as of August 2020, having previously served as Vice President, Corporate Planning & Development since June 2018. Prior to that, he served as Vice President, Mid-Continent Business Unit in the Lower 48 from September 2016 to Jun 2018 and Vice President, North Slope Operations and Development in Alaska from August 2012 to September 2016.

Kelly B. Rose was appointed Senior Vice President, Legal, General Counsel in September 2018. Prior to th 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.

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	
		2020	20
First	$	**0.420**	0.3
Second		**0.420**	0.3
Third		**0.420**	0.3
Fourth		**0.430**	0.4

Number of Stockholders of Record at January 31, 2021*	40,4

**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 indebtedne 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.

Issuer Purchases of Equity Securities

						Millions of Doll
Period	Total Number of Shares Purchased*		Average Price Paid Per Share	Shares Purchased as Part of Publicly Announced Plans or Programs		Approximate Dollar Value of Sha that May Yet I Purchased Under t Plans or Progra
October 1-31, 2020	4,805,220	$	34.68	4,805,220	$	14,48
November 1-30, 2020	-		-	-		14,48
December 1-31, 2020	-		-	-		14,48
	4,805,220	$	34.68	4,805,220		

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

In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. As of December 31, 2020, we had repurchased $10.5 billion of shares. Repurchases 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 "Item 1A—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 TSR for ConocoPhillips' common stock in each of the five years from December 31, 2015 to December 31, 2020. The graph also compares the cumulative total returns for th same five-year period with the S&P 500 Index and our performance peer group consisting of Chevron, ExxonMobil, Apache, Marathon Oil Corporation, Devon, Occidental, Hess, and EOG weighted according to the respective peer's stock market capitalization at the beginning of each annual period. For the 2019 Stock Performance Graph, Noble Energy was also presented within the peer group. However, due to Chevron's acquisition of Noble Energy completed in 2020, Noble Energy's performance has been excluded from all fiv years of the peer group performance.

The comparison assumes $100 was invested on December 31, 2015, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer group 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.

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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 contain 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 o the Private Securities Litigation Reform Act of 1995. The words "anticipate," "believe," "budget," "continue," "could," "effort," "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "objective," "outlook," "plan," "potential," "predict," "projection," "seek," "should," "target," "will," "would," 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 O THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 75.

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

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is an independent E&P company with operations and activities in 15 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe and Asia; LNG developments; oil sands assets in Canada; and an inventory global conventional and unconventional exploration prospects. Headquartered in Houston, Texas, at December 31, 2020, we employed approximately 9,700 people worldwide and had total assets of $63 billion

Completed Acquisition of Concho Resources Inc.

On January 15, 2021, we completed our acquisition of Concho Resources Inc. (Concho), an independent oil and gas exploration and production company with operations across New Mexico and West Texas. The addition of complementary acreage in the Delaware and Midland Basins creates a sizeable Permian presenc augment our leading unconventional positions in the Eagle Ford and Bakken in the Lower 48 and the Montn in Canada.

Consideration for the all-stock transaction was valued at $13.1 billion, in which 1.46 shares of ConocoPhilli common stock was exchanged for each outstanding share of Concho common stock, resulting in the issuanc of approximately 286 million shares of ConocoPhillips common stock. We also assumed $3.9 billion in aggregate principal amount of outstanding debt for Concho, which was recorded at fair value of $4.7 billion as of the closing date. The combined companies are expected to capture approximately $750 million of annual cost and capital savings by 2022. For additional information related to this transaction, see Note 25—Acquisition of Concho Resources Inc. in the Notes to Consolidated Financial Statements.

Overview

The energy landscape changed dramatically in 2020 with simultaneous demand and supply shocks that drov the industry into a severe downturn. The demand shock was triggered by the COVID-19 pandemic, which continues to have unprecedented social and economic consequences. Mitigation efforts to stop the spread o this highly-contagious disease include stay-at-home orders and business closures that caused sharp contractions in economic activity worldwide. The supply shock was triggered by disagreements between OPEC and Russia, beginning in early March 2020, which resulted in significant supply coming onto the market and an oil price war. These dual demand and supply shocks caused oil prices to collapse as we exite the first quarter of 2020.

As we entered the second quarter of 2020, predictions of COVID-19 driven global oil demand losses intensified, with forecasts of unprecedented demand declines. Based on these forecasts, OPEC plus nations held an emergency meeting, and in April they announced a coordinated production cut that was unprecedent in both its magnitude and duration. The OPEC plus agreement spans from May 2020 until April 2022, with the volume of production cuts easing over time. Additionally, non-OPEC plus countries, including the U.S., Canada, Brazil and other G-20 countries, announced organic reductions to production through the release of drilling rigs, frac crews, normal field decline and curtailments. Despite these planned production decreases, the supply cuts were not timely enough to overcome significant demand decline. Futures prices for April W closed under $20 a barrel for the first time since 2001, followed by May WTI settling below zero on the day before futures contracts expiry, as holders of May futures contracts struggled to exit positions and avoid taki physical delivery. As storage constraints approached, spot prices in April for certain North American landlocked grades of crude oil were in the single digits or even negative for particularly remote or low-grade crudes, while waterborne priced crudes such as Brent sold at a relative advantage. The extreme volatility experienced in the first half of the year settled down in the second half of the year, with WTI crude oil prices exiting the year near $50 per barrel.

Since the start of the severe downturn, we have closely monitored the market and taken prudent actions in response to this situation. We entered 2020 in a position of relative strength, with cash and cash equivalents of more than $5 billion, short-term investments of $3 billion, and an undrawn credit facility of $6 billion, totali approximately $14 billion in available liquidity. Additionally, we had several entity and asset sales agreements in place, which generated $1.3 billion in proceeds from dispositions during 2020. For more information about the sales of our Australia-West and non-core Lower 48 assets, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements. This relative advantage allowed us to be measured in our response to the sudden change in business environment.

In March, we announced an initial set of actions to address the downturn and followed up with additional actions in April. The combined announcements reflected a reduction in our 2020 operating plan capital of $ billion, a reduction to our operating costs of $600 million and suspension of our share repurchase program. These actions decreased uses of cash by approximately $5 billion in 2020. We also established a framework for evaluating our assets and implementing economic production curtailments considering the weakness in c prices during the second quarter of 2020, which resulted in taking an additional significant step of voluntaril curtailing production, predominantly from operated North American assets. Due to our strong balance sheet we were in an advantaged position to forgo some production and cash flow in anticipation of receiving high cash flows for those volumes in the future.

In the second quarter, we curtailed production by an estimated 225 MBOED, with 145 MBOED of the curtailments from the Lower 48, 40 MBOED from Alaska and 30 MBOED from our Surmont operation in Canada. The remainder of the second-quarter curtailments were primarily in Malaysia. Other industry operators also cut production and development plans and as we progressed through the second quarter, certa stay-at-home restrictions eased, which partially restored lost demand, and WTI and Brent prices exited the second quarter around $40 per barrel. Based on our economic framework, we began restoring production fr voluntary curtailments in July, and with oil stabilizing around $40 per barrel, we ended our curtailment program during the third quarter. Curtailments in the third quarter averaged approximately 90 MBOED, wit 65 MBOED attributable to the Lower 48 and 15 MBOED to Surmont.

In August 2020, we acquired additional Montney acreage for cash consideration of $382 million, after customary post-closing adjustments. We also assumed $31 million in financing obligations for associated partially owned infrastructure. This acquisition consisted primarily of undeveloped properties and included 140,000 net acres in the liquids-rich Inga Fireweed asset Montney zone, which is directly adjacent to our existing Montney position. The transaction increased our Montney acreage position to approximately 295,0 net acres with a 100 percent working interest. See Note 4—Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.

In October 2020, we announced an increase to our quarterly dividend from $0.42 per share to $0.43 per shar and resumed share repurchases before suspending our share repurchase program upon entry into our definiti agreement to acquire Concho. We resumed shares repurchases in February 2021 after completion of our Concho acquisition. We ended the year with over $12 billion of liquidity, comprised of $3.0 billion in cash and cash equivalents, $3.6 billion in short-term investments, and available borrowings under our credit facili of $5.7 billion.

Our expectation is that commodity prices will remain cyclical and volatile, and a successful business strateg in the E&P industry must be resilient in lower price environments, at the same time retaining upside during periods of higher prices. While we are not impervious to current market conditions, we believe our decisive actions over the last several years of focusing on free cash flow generation, high-grading our asset base, lowering the cost of supply of our investment resource portfolio, and strengthening our balance sheet have p us in a strong relative position compared to our independent E&P peers. We remain committed to the core principles of our value proposition, namely, free cash flow generation, a strong balance sheet, commitment t differential returns of and on capital, and ESG leadership.

Our workforce and operations have adjusted to mitigate the impacts of the COVID-19 pandemic. We have operations in remote areas with confined spaces, such as offshore platforms, the North Slope of Alaska, Curt Island in Australia, western Canada and Indonesia, where viruses could rapidly spread. Personnel are asked perform a self-assessment for symptoms of illness each day and, when appropriate, are subject to more restrictive measures before traveling to and working on location. Staffing levels in certain operating locatio have been reduced to minimize health risk exposure and increase social distancing. A portion of our office staff have continued to work successfully remotely, with offices around the world carefully designing and executing a flexible, phased reentry, following national, state and local guidelines. These mitigation measures have thus far been effective at reducing business operation disruptions. Workforce health and safety remains the overriding driver for our actions and we have demonstrated our ability to adapt to local conditions as warranted.

The marketing and supply chain side of our business has also adapted in response to COVID-19. Our commercial organization managed transportation commitments during our voluntary curtailment program. Our supply chain function is proactively working with vendors to ensure the continuity of our business operations, monitor distressed service and materials providers, capture deflation opportunities, and pursue co reduction efforts. We also enhanced our focus on counterparty risk monitoring during this period and requested credit assurances when applicable.

Operationally, we remain focused on safely executing the business. In 2020, production of 1,127 MBOED generated cash provided by operating activities of $4.8 billion. We invested $4.7 billion into the business in the form of capital expenditures, including $0.5 billion of acquisition capital, and paid dividends to shareholders of $1.8 billion. Production decreased 221 MBOED or 16 percent in 2020, compared to 2019. Production excluding Libya for 2020 was 1,118 MBOED. Adjusting for estimated curtailments of approximately 80 MBOED; closed acquisitions and dispositions; and excluding Libya, production for 2020 would have been 1,176 MBOED, a decrease of 15 MBOED compared with 2019 production. This decrease was primarily due to normal field decline, partly offset by new wells online in the Lower 48, Canada, Norwa Alaska and China. Production from Libya averaged 9 MBOED as it was in force majeure during a significa portion of the year.

Key Operating and Financial Summary

Significant items during 2020 and recent announcements included the following:

- Enhanced both our portfolio and financial framework through the acquisition of Concho in an all-stock transaction, as well as purchasing bolt-on acreage in Canada and Lower 48.
- Full-year production, excluding Libya, of 1,118 MBOED; curtailed approximately 80 MBOED during th year.

- Cash provided by operating activities was $4.8 billion.
- Generated $1.3 billion in disposition proceeds from non-core asset sales.
- Distributed $1.8 billion in dividends and repurchased $0.9 billion of shares.
- Ended the year with cash and cash equivalents totaling $3.0 billion and short-term investments of $3.6 billion, equaling $6.6 billion in ending cash and cash equivalents and short-term investments.
- Announced two significant discoveries in Norway and achieved first production at Tor II; continued appraisal drilling and started up first pads and related infrastructure in Montney.
- Adopted a Paris-aligned climate risk framework with ambition to achieve net-zero operated emissions by 2050 as part of our commitment to ESG excellence.
- Recognized impairments of proved and unproved properties totaling $1.3 billion after-tax.

Business Environment

Brent crude oil prices averaged $42 per barrel in 2020, compared with $64 per barrel in 2019. 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 to create value through price cycles by delivering on the foundational principles that underpin our value proposition; free cash flow generation, a strong balance sheet, commitment to differential returns of and on capital, and ESG leadership.

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

- Free cash flow generation. This is a core principle of our value proposition. Our goal is to achieve strong free cash flow by exercising capital discipline, controlling our costs, and safely and reliably delivering production. Throughout the price cycles, we expect to make capital investments sufficient to sustain production. Free cash flow provides funds that are available to return to shareholders, strengthen the balance sheet to deliver on our priorities through the price cycles, or reinvest back in the business for future cash flow expansion.

    - 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 we believe will lead to value maximization and cash flow expansion using an optimized investment pace, not production growth for growth's sake. Our cash allocation priorities call for the investment of sufficient capital to sustain production and pay the existing dividend. Additional capital may be allocated toward growth, but discipline will be maintained.

      In February 2021, we announced 2021 operating plan capital for the combined company of $5.5 billion. The plan includes $5.1 billion to sustain current production and $0.4 billion for investment in major projects, primarily in Alaska, in addition to ongoing exploration appraisal activity.

      The operating plan capital budget of $5.5 billion is expected to deliver production from the combined company of approximately 1.5 MMBOED in 2021. This production excludes Libya.

- Control costs and expenses. Controlling operating and overhead costs, without compromis 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 absolut 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 2020, our production and operating expenses were percent lower than 2019, primarily due to decreased wellwork and transportation costs resulting from production curtailments across our North American operated assets as well a the absence of costs related to our U.K. and Australia-West divestitures. For more information related to our U.K. and Australia-West divestitures, see note 4—Acquisitions a Dispositions in the Notes to Consolidated Financial Statements.

  At the time of the Concho acquisition announcement in October 2020, we announced plann cost reductions and quantified $350 million of annual expense savings expected to be achieved by 2022. These reductions included approximately $150 million due to streamlin our internal organization to appropriate levels given the current industry environment and recent asset sales; $100 million of G&A and G&G due to a refocused exploration program; and $100 million of redundant G&A costs on a combined basis related to the Concho acquisition. Subsequent to the transaction announcement, we identified $250 million of further cost reductions from the combined companies to be achieved by 2022.

- Optimize our portfolio. In January 2021, we completed the acquisition of Concho and significantly increased our unconventional portfolio with years of low cost of supply investments. The addition of complementary acreage in the Delaware and Midland basins creates a sizeable Permian presence to augment our leading unconventional positions in the Eagle Ford and Bakken in the Lower 48. We added to our unconventional Montney position with an asset acquisition that consisted primarily of undeveloped properties directly adjace to our existing acreage.

  These acquisitions followed several non-core asset sales earlier in the year including Australia-West in our Asia Pacific segment, and Niobrara and Waddell Ranch in the Lower 48. We managed the portfolio well during a turbulent year, with asset sales entered at the end of 2019 generating $1.3 billion of proceeds from dispositions in the first half of 2020, followed by opportunistic acquisitions of unconventional assets in the second half of 2020 after commodity prices had dropped. 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.

- A strong balance sheet. 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 o priorities through the price cycles. Our priorities include execution of our development plans, maintaining a growing dividend, and returning competitive returns of capital to shareholders.

- Commitment to differential returns of and on capital. We believe in delivering value to our shareholders via a growing, sustainable dividend supplemented by additional returns of capital, including share repurchases. In 2020, we paid dividends on our common stock of approximately $1 billion and repurchased $0.9 billion of our common stock. Combined, our dividend and repurchase represented 57 percent of our net cash provided by operating activities. Since we initiated our curre share repurchase program in late 2016, we have repurchased 189 million shares for $10.5 billion, which represents approximately 15 percent of shares outstanding as of September 30, 2016. As of December 31, 2020, $14.5 billion of repurchase authority remained of the $25 billion share repurch program our Board of Directors had authorized. Repurchases are made at management's discretio at prevailing prices, subject to market conditions and other factors. See “Item 1A—Risk Factors Ou ability to declare and pay dividends and repurchase shares is subject to certain considerations.”

In October 2020, we announced that our Board of Directors approved an increase to our quarterly dividend of $0.42 per share to $0.43 per share. In February 2021, we resumed share repurchases aft the completion of our Concho acquisition.

- ESG Leadership. 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, in October 2020, we announced our adoption of a Par aligned climate risk framework as part of our continued leadership in ESG excellence. This comprehensive climate risk strategy should enable us to sustainably meet global energy demand wh delivering competitive returns through the energy transition. We have set a target to reduce our gross operated (scope 1 and 2) emissions intensity by 35 to 45 percent from 2016 levels by 2030, with an ambition to achieve net zero by 2050 for operated emissions. We are advocating for reduction of scope 3 end-use emissions intensity through our support for a U.S. carbon price and reaffirmed our commitment to the Climate Leadership Council. We have joined the World Bank Flaring Initiative work towards zero routine flaring of gas by 2030 and are the first U.S.-based oil and gas company to adopt a Paris-aligned climate risk strategy.

- Add to our proved reserve base. We primarily add to our proved reserve base in three ways:
  - Purchases of increased interests in existing fields and acquisitions.
  - Application of new technologies and processes to improve recovery from existing fields.
  - Successful exploration, exploitation and development of new and existing fields.

As required by current authoritative guidelines, the estimated future date when an asset will reach th end of its economic life is based on historical 12-month first-of-month average prices and current costs. This date estimates when production will end and 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.

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. Our reserve replacement was negative 86 percent in 2020, reflecting the impact of lower prices, which reduced reserves by approximately 600 MMBOE. Our organic reserve replacement, which excluded a net decrease of 7 MMBOE from sales and purchases, was negative 84 percent in 2020.

In the three years ended December 31, 2020, our reserve replacement was 59 percent, primarily impacted by lower prices in 2020. Our organic reserve replacement during the three years ended December 31, 2020, which excluded a net increase of 89 MMBOE related to sales and purchases, w 53 percent.

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 acce 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, o 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 conve additional resources to reserves, achieve greater operating efficiencies and reduce our environmenta impact. Companywide, we continue 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 emissions monitoring, seismic advancements and advanced controls in our field operations.

- Attract, develop and retain a talented work force. We strive to attract, develop and retain individuals with the knowledge and skills to successfully execute our business strategy in a manner exemplifyi our core 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 OPE and other producing countries, 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:

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  Brent crude oil prices averaged $41.68 per barrel in 2020, a decrease of 35 percent compared with $64.30 per barrel in 2019. Similarly, WTI crude oil prices decreased 31 percent from $57.02 per barrel in 2019 to $39.37 per barrel in 2020. Crude oil prices were lower due to the dual demand an supply shocks. The demand shock was triggered by the COVID-19 pandemic, which continues to have unprecedented social and economic consequences. The supply shock was triggered disagreements between OPEC and Russia, beginning in early March 2020, which resulted in significant supply coming onto the market and created higher inventory levels.

Henry Hub natural gas prices decreased 21 percent from an average of $2.63 per MMBTU in 2019 t $2.08 per MMBTU in 2020. Henry Hub prices were depressed due to high storage levels and weak demand.

Our realized bitumen price decreased 75 percent from an average of $31.72 per barrel in 2019 to $8 per barrel in 2020. The decrease was largely driven by weakness in WTI, reflective of impacts from the COVID-19 pandemic. The WCS differential to WTI at Hardisty remained fairly flat as curtailment orders imposed by the Alberta Government, which limited production from the province continued throughout 2020. We continue to optimize bitumen price realizations through improvements in alternate blend capability which results in lower diluent costs and access to the U.S Gulf Coast market through rail and pipeline contracts.

Our worldwide annual average realized price decreased 34 percent from $48.78 per BOE in 2019 to $32.15 per BOE in 2020 primarily due to lower realized oil, natural gas and bitumen prices.

North America's energy supply landscape has been transformed from one of resource scarcity to on 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 opportuniti 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 unconventional fields. Should one or more of these events occur, our revenues would be reduced, a 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 tim our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-dov 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 impairmen charges to long-lived assets used in operations, investments in nonconsolidated entities accounted f under the equity method, and unproved properties. For additional information on our impairments, see Note 7—Suspended Wells and Exploration Expenses and Note 8—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, regulato 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 manageme carefully considers the fiscal and regulatory environment when evaluating projects or determining t levels and locations of our activity.

Outlook

Production and Capital
In February 2021, we announced 2021 operating plan capital for the combined company of $5.5 billion. Th
plan includes $5.1 billion to sustain current production and $0.4 billion for investment in major projects, primarily in Alaska, in addition to ongoing exploration appraisal activity.

The operating plan capital budget of $5.5 billion is expected to deliver production from the combined compa
of approximately 1.5 MMBOED in 2021. This production guidance excludes
Libya.

Restructuring
As a result of the acquisition of Concho, we commenced a restructuring program in the first quarter of 2021
association with combining the operations of the two companies. We expect to incur significant non-
recurring transaction and acquisition-related costs in 2021 for employee severance payments; incremental pension benefit costs related to the workforce reductions; employee retention costs; employee relocations; fees paid t
financial, legal, and accounting advisors; and filing fees. We currently cannot estimate these costs, as well
as other unanticipated items, and expect to recognize the majority of these expenses in the first quarter of 2021

Operating Segments

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

Corporate and Other represents income and 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 productio

RESULTS OF OPERATIONS

Effective with the third quarter of 2020, we have restructured our segments to align with changes to our internal organization. The Middle East business was realigned from the Asia Pacific and Middle East segm to the Europe and North Africa segment. The segments have been renamed the Asia Pacific segment and the Europe, Middle East and North Africa segment. We have revised segment information disclosures and segment performance metrics presented within our results of operations for the current and prior years.

This section of the Form 10-K discusses year-to-year comparisons between 2020 and 2019. For discussion year-to-year comparisons between 2019 and 2018, see "Management's Discussion and Analysis of Financia Condition and Results of Operations" in Exhibit 99.1—, Item 7 filed with our Form 8-K filed on November 2020.

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		**2020**	2019	20
Alaska	$	**(719)**	1,520	1,8
Lower 48		**(1,122)**	436	1,7
Canada		**(326)**	279	
Europe, Middle East and North Africa		**448**	3,170	2,5
Asia Pacific		**962**	1,483	1,3
Other International		**(64)**	263	3
Corporate and Other		**(1,880)**	38	(1,6
Net income (loss) attributable to ConocoPhillips	$	**(2,701)**	7,189	6,2

2020 vs. 2019

Net income (loss) attributable to ConocoPhillips decreased $9.9 billion in 2020. The decrease was mainly due to:

- Lower realized commodity prices.
- Lower sales volumes due to normal field decline, asset dispositions and production curtailments. Fo additional information related to dispositions, see Note 4—Asset Acquisitions and Dispositions in th Notes to Consolidated Financial Statements.
- The absence of a $2.1 billion after-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries. For additional information, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- An unrealized loss of $855 million after-tax on our Cenovus Energy (CVE) common shares in 2020 as compared to a $649 million after-tax unrealized gain on those shares in 2019.
- A $648 million after-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs and an equity method investment related to our Alaska North Slope Gas asset. For additional information, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.
- Increased impairments primarily related to developed properties in our non-core assets which were written down to fair value due to lower commodity prices and development plan changes. For additional information, see Note 8—Impairments and Note 14—Fair Value Measurement in the Not to Consolidated Financial Statements.
- The absence of other income of $317 million after-tax related to our settlement agreement with PDVSA.

These decreases in net income (loss) were partly offset by:

- Lower production and operating expenses, primarily due to the absence of costs related to our U.K. and Australia-West divestitures and decreased wellwork and transportation costs resulting from production curtailments across our North American operated assets.
- A $597 million after-tax gain on dispositions related to our Australia-West divestiture.
- Lower DD&A expenses, primarily due to lower volumes related to normal field decline and production curtailments as well as impacts of our Australia-West and U.K. divestitures. Partly offsetting this decrease, was higher DD&A expenses due to price-related downward reserve revisio

Income Statement Analysis

2020 vs. 2019

Sales and other operating revenues decreased 42 percent in 2020, mainly due to lower realized commodity prices and lower sales volumes. Sales volumes decreased due to normal field decline, production curtailmen from our North American operated assets and the divestiture of our U.K. assets in the third quarter of 2019 a our Australia-West assets in the second quarter of 2020.

Equity in earnings of affiliates decreased $347 million in 2020, primarily due to lower earnings from QG3 a APLNG because of lower LNG prices. Partly offsetting this decrease was the absence of impairments relate to equity method investments in our Lower 48 segment of $155 million and the absence of a $118 million deferred tax adjustment at QG3, reported in our Europe, Middle East and North Africa segment.

Gain on dispositions decreased $1.4 billion in 2020, primarily due to the absence of a $1.7 billion before-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries. Partly offsetting th decrease was a $587 million before-tax gain associated with our Australia-West divestiture. For more information related to these dispositions, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

Other income (loss) decreased $1.9 billion in 2020, primarily due to a before-tax unrealized loss of $855 million on our CVE common shares in 2020, and the absence of a $649 million before-tax unrealized gain o those shares in 2019. Additionally, other income (loss) decreased due to the absence of $325 million before tax related to our settlement agreement with PDVSA.

For discussion of our CVE shares, see Note 6—Investment in Cenovus Energy in the Notes to Consolidated Financial Statements. For discussion of our PDVSA settlement, see Note 12—Contingencies and Commitments in the Notes to Consolidated Financial Statements.

Purchased commodities decreased 32 percent in 2020, primarily due to lower natural gas and crude oil price lower crude oil and natural gas volumes purchased; and the divestiture of our U.K. assets in the third quarter 2019 and our Australia-West assets in the second quarter of 2020.

Production and operating expenses decreased $978 million in 2020, primarily due to reduced activities and transportation costs associated with lower activity across our North American operated assets in response to the low commodity price environment and the absence of costs related to our U.K. and Australia-West divestitures.

Selling, general and administrative expenses decreased $126 million in 2020, primarily due to lower costs associated with compensation and benefits, including mark to market impacts of certain key employee compensation programs.

Exploration expenses increased $714 million in 2020, primarily due to an $828 million before-tax impairme for the entire carrying value of capitalized undeveloped leasehold costs related to our Alaska North Slope Ga asset. Partly offsetting this increase, was the absence of a $141 million before-tax leasehold impairment expense due to our decision to discontinue exploration activities in the Central Louisiana Austin Chalk trend For additional information, see Note 7—Suspended Wells and Exploration Expenses, in the Notes Consolidated Financial Statements.

Impairments increased $408 million in 2020, primarily related to developed properties in our non-core assets which were written down to fair value due to lower commodity prices and development plan changes. For additional information, see Note 8—Impairments and Note 14—Fair Value Measurement in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased $199 million in 2020, primarily due to lower commodity prices an volumes.

Foreign currency transaction (gains) losses decreased $138 million in 2020, due to gains recognized from foreign currency derivatives and other foreign currency remeasurements. For additional information, see No 13—Derivative and Financial Instruments in the Notes to Consolidated Financial Statements.

See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding o income tax provision (benefit) and effective tax rate.

Summary Operating Statistics

	2020	2019	20
Average Net Production			
Crude oil (MBD)			
Consolidated Operations	**555**	692	6
Equity affiliates	**13**	13	
Total crude oil	**568**	705	6
Natural gas liquids (MBD)			
Consolidated Operations	**97**	107	
Equity affiliates	**8**	8	
Total natural gas liquids	**105**	115	1
Bitumen (MBD)	**55**	60	
Natural gas (MMCFD)			
Consolidated Operations	**1,339**	1,753	1,7
Equity affiliates	**1,055**	1,052	1,0
Total natural gas	**2,394**	2,805	2,7
Total Production (MBOED)	**1,127**	1,348	1,2
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per bbl)			
Consolidated Operations	**$ 39.56**	60.98	68.
Equity affiliates	**39.02**	61.32	72.
Total crude oil	**39.54**	60.99	68.
Natural gas liquids (per bbl)			
Consolidated Operations	**12.90**	18.73	29.
Equity affiliates	**32.69**	36.70	45.
Total natural gas liquids	**14.61**	20.09	30.
Bitumen (per bbl)	**8.02**	31.72	22.
Natural gas (per mcf)			
Consolidated Operations	**3.17**	4.25	5.
Equity affiliates	**3.71**	6.29	6.
Total natural gas	**3.41**	5.03	5.
	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical, lease rental, and other	**$ 374**	322	2
Leasehold impairment	**868**	221	
Dry holes	**215**	200	
	$ 1,457	743	3

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwi basis. At December 31, 2020, our operations were producing in the U.S., Norway, Canada, Australia, Indonesia, China, Malaysia, Qatar and Libya.

2020 vs. 2019

Total production, including Libya, of 1,127 MBOED decreased 221 MBOED or 16 percent in 2020 compare with 2019, primarily due to:

- Normal field decline.
- The divestiture of our U.K. assets in the third quarter of 2019 and our Australia-West assets in the second quarter of 2020.
- Production curtailments of approximately 80 MBOED, primarily from North American operated assets and Malaysia, in response to the low crude oil price environment.
- Less production in Libya due to the forced shutdown of the Es Sider export terminal and other easte export terminals after a period of civil unrest.

The decrease in production during 2020 was partly offset by:

- New wells online in the Lower 48, Canada, Norway, Alaska and China.

Production excluding Libya for 2020 was 1,118 MBOED. Adjusting for estimated curtailments of approximately 80 MBOED and closed acquisitions and dispositions, production for 2020 would have been 1,176 MBOED, a decrease of 15 MBOED compared with 2019. This decrease was primarily due to normal field decline, partly offset by new wells online in the Lower 48, Canada, Norway, Alaska and China. Production from Libya averaged 9 MBOED as it was in force majeure during a significant portion of the yea

Alaska

		2020	2019	20
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$	**(719)**	1,520	1,8
Average Net Production				
Crude oil (MBD)		**181**	202	1
Natural gas liquids (MBD)		**16**	15	
Natural gas (MMCFD)		**10**	7	
Total Production (MBOED)		**198**	218	1
Average Sales Prices				
Crude oil ($ per bbl)	$	**42.12**	64.12	70.
Natural gas ($ per mcf)		**2.91**	3.19	2.

The Alaska segment primarily explores for, produces, transports and markets crude oil, NGLs and natural ga In 2020, Alaska contributed 28 percent of our consolidated liquids production and less than 1 percent of our consolidated natural gas production.

2020 vs. 2019

Net Income (Loss) Attributable to ConocoPhillips
Alaska reported a loss of $719 million in 2020, compared with earnings of $1,520 million in 2019. Earning were negatively impacted by:

- Lower realized crude oil prices.
- A $648 million after-tax impairment associated with the carrying value of our Alaska North Slope G assets. For additional information, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.
- Lower sales volumes, primarily due to normal field decline and production curtailments at our operated assets on the North Slope—the Greater Kuparuk Area (GKA) and Western North Slope (WNS).
- Higher DD&A expenses, primarily from increased DD&A rates due to price-related downward reserve revisions, partly offset by lower production volumes.
- Increased exploration expenses, primarily due to higher dry hole costs and expenses related to the early cancellation of our winter exploration program.

Earnings were positively impacted by:

- Lower production and operating expenses, primarily associated with lower transportation and terminaling costs as well as lower activities across our assets.

Production
Average production decreased 20 MBOED in 2020 compared with 2019, primarily due to:

- Normal field decline.
- Production curtailments at our operated assets on the North Slope—GKA and WNS—of 8 MBOEI in response to the low crude oil price environment.

These production decreases were partly offset by:

- Lower downtime due to the absence of planned turnarounds at the Greater Prudhoe Area.
- New wells online at our operated assets on the North Slope—GKA and WNS.

Lower 48

		2020	2019	20
Net Income (Loss) Attributable to ConocoPhillips				
(millions of dollars)	$	**(1,122)**	436	1,7
Average Net Production				
Crude oil (MBD)		**213**	266	2
Natural gas liquids (MBD)		**74**	81	
Natural gas (MMCFD)		**585**	622	5
Total Production (MBOED)		**385**	451	3
Average Sales Prices				
Crude oil ($ per bbl)	$	**35.17**	55.30	62.
Natural gas liquids ($ per bbl)		**12.13**	16.83	27.
Natural gas ($ per mcf)		**1.65**	2.12	2.

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf of Mexico. Durin 2020, the Lower 48 contributed 40 percent of our consolidated liquids production and 44 percent of our consolidated natural gas production.

2020 vs. 2019

Net Income (Loss) Attributable to ConocoPhillips
Lower 48 reported a loss of $1,122 million in 2020, compared with earnings of $436 million in 2019. Earnings were negatively impacted by:

- Lower realized crude oil, NGL and natural gas prices.
- Lower crude oil sales volumes due to normal field decline and production curtailments.
- Higher impairments, primarily related to developed properties in our non-core assets which were written down to fair value due to lower commodity prices and development plan changes. See Note 8—Impairments and Note 14—Fair Value Measurement, for additional information.

Earnings were positively impacted by:

- Lower exploration expenses, primarily due to the absence of 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.
- Lower DD&A expenses, primarily due to normal field decline and production curtailments, partly offset by increased DD&A rates due to price-related downward reserve revisions.
- Lower production and operating expenses, primarily due to lower activities driven by production curtailments in response to the low price environment and disposition impacts.
- Lower taxes other than income taxes, primarily due to lower realized prices and volumes.

Production
Total average production decreased 66 MBOED in 2020 compared with 2019, primarily due to:

- Normal field decline.
- Production curtailments of approximately 55 MBOED in response to the low crude oil price environment.

These production decreases were partly offset by:

- New wells online from the Eagle Ford, Permian and Bakken.

Canada

		2020*	2019**	201
Net Income (Loss) Attributable to ConocoPhillips				
(millions of dollars)	$	**(326)**	279	
Average Net Production				
Crude oil (MBD)		**6**	1	
Natural gas liquids (MBD)		**2**	-	
Bitumen (MBD)		**55**	60	
Natural gas (MMCFD)		**40**	9	
Total Production (MBOED)		**70**	63	
Average Sales Prices				
Crude oil ($ per bbl)	$	**23.57**	40.87	48.
Natural gas liquids ($ per bbl)		**5.41**	19.87	43.
Bitumen ($ per bbl)		**8.02**	31.72	22.
Natural gas ($ per mcf)		**1.21**	0.49	1.

**Average sales prices include unutilized transportation costs.*
***Average prices for sales of bitumen produced 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 2020, Canada contributed 9 percent of our consolidat liquids production and 3 percent of our consolidated natural gas production.

2020 vs. 2019

Net Income (Loss) Attributable to ConocoPhillips
Canada operations reported a loss of $326 million in 2020 compared with earnings of $279 million in 2019. Earnings decreased mainly due to:

- Lower realized bitumen prices.
- Higher DD&A expenses, primarily due to increased volumes and DD&A rates from Montney production
- Lower bitumen sales due to production curtailments at Surmont.

Earnings were positively impacted by:

- Increased Montney production from Pad 1 & 2 wells online and partial year production from the Kelt acquisition completed in August of 2020.

Production
Total average production increased 7 MBOED in 2020 compared with 2019. The production increase was primarily due to:

- Increased liquids and natural gas production from Montney Pad 1 & 2 wells online and partial year production from the Kelt acquisition completed in August of 2020.
- Decreased mandated production curtailments imposed by the Alberta government.

The production increase was partly offset by:

- Lower bitumen production, primarily due to voluntary curtailments at Surmont in response to the low pri environment of 12 MBOED.

Europe, Middle East and North Africa

		2020	2019*	20
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**448**	3,170	2,5
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**86**	138	1
Natural gas liquids (MBD)		**4**	7	
Natural gas (MMCFD)		**275**	478	5
Total Production (MBOED)		**136**	224	2
Average Sales Prices				
Crude oil ($ per bbl)	$	**43.30**	64.94	70.
Natural gas liquids ($ per bbl)		**23.27**	29.37	36.
Natural gas ($ per mcf)		**3.23**	4.92	7.

**Prior periods have been updated to reflect the Middle East Business Unit moving from Asia Pacific to the Europe, Middle East and North Af segment. See Note 24—Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements for additional information.*

The Europe, Middle East and North Africa segment consists of operations principally located in the Norweg sector of the North Sea; the Norwegian Sea; Qatar; Libya; and commercial and terminalling operations in th U.K. In 2020, our Europe, Middle East and North Africa operations contributed 13 percent of our consolidated liquids production and 20 percent of our consolidated natural gas production.

2020 vs. 2019

Net Income Attributable to ConocoPhillips
Earnings for Europe, Middle East and North Africa operations of $448 million decreased $2,722 million in 2020 compared with 2019. The decrease in earnings was primarily due to:

- The absence of a $2.1 billion after-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries. For additional information, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- Lower equity in earnings of affiliates, primarily due to lower LNG sales prices.
- Lower realized crude oil prices in Norway.

In the fourth quarter of 2020, the effective tax rate within our equity method investment in the Europe, Midc East and North Africa segment increased.

Consolidated Production
Average consolidated production decreased 88 MBOED in 2020, compared with 2019. The decrease was mainly due to:

- The absence of production related to our U.K. disposition in the third quarter of 2019.
- Lower volumes from Libya due to a cessation of production following a period of civil unrest.
- Normal field decline.

These production decreases were partly offset by:

- New wells online in Norway.

Asia Pacific

		2020	2019*	20
Net Income Attributable to ConocoPhillips				
(millions of dollars)	$	**962**	1,483	1,3
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**69**	85	
Natural gas liquids (MBD)		**1**	4	
Natural gas (MMCFD)		**429**	637	6
Total Production (MBOED)		**141**	196	1
Average Sales Prices				
Crude oil ($ per bbl)	$	**42.84**	65.02	70.
Natural gas liquids ($ per bbl)		**33.21**	37.85	47.
Natural gas ($ per mcf)		**5.39**	5.91	6.

**Prior periods have been updated to reflect the Middle East Business Unit moving from Asia Pacific to the Europe, Middle East and North Af segment. See Note 24—Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements for additional information.*

The Asia Pacific segment has operations in China, Indonesia, Malaysia and Australia. During 2020, Asia Pacific contributed 10 percent of our consolidated liquids production and 32 percent of our consolidated natural gas production.

2020 vs. 2019

Net Income Attributable to ConocoPhillips
Asia Pacific reported earnings of $962 million in 2020, compared with $1,483 million in 2019. The decreas in earnings was mainly due to:

- Lower sales volumes, primarily from lower LNG sales due to the Australia-West divestiture; lower crude oil sales volumes in Malaysia, primarily due to production curtailments; and lower crude oil s volumes in China due to the expiration of the Panyu production license. For more information relat our Australia-West divestiture, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- Lower realized commodity prices.
- Lower equity in earnings of affiliates from APLNG, mainly due to lower LNG sales prices.
- The absence of a $164 million income tax benefit related to deepwater incentive tax credits from the Malaysia Block G.

Earnings were positively impacted by:

- A $597 million after-tax gain on disposition related to our Australia-West divestiture.

Consolidated Production
Average consolidated production decreased 28 percent in 2020, compared with 2019. The decrease was primarily due to:

- The divestiture of our Australia-West assets.
- Normal field decline.
- Higher unplanned downtime due to the rupture of a third-party pipeline impacting gas production fr the Kebabangan Field in Malaysia.
- The expiration of the Panyu production license in China.
- Production curtailments of 4 MBOED in Malaysia.

These production decreases were partly offset by:

- Development activity at Bohai Bay in China and Gumusut in Malaysia.

Other International

		2020	2019	20
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$	**(64)**	263	36

The Other International segment includes exploration activities in Colombia and Argentina and contingencie associated with prior operations in other countries. As a result of our completed Concho acquisition on January 15, 2021, we refocused our exploration program and announced our intent to pursue a managed exit from certain areas.

2020 vs. 2019

Other International operations reported a loss of $64 million in 2020, compared with earnings of $263 millio in 2019. The decrease in earnings was primarily due to:

- The absence of $317 million after-tax in other income from a settlement award with PDVSA associated with prior operations in Venezuela. For additional information related to this settlement award, see Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.
- Increased exploration expenses, primarily due to dry hole costs and a full impairment of capitalized undeveloped leasehold costs in Colombia.

Corporate and Other

		Millions of Dollars		
		2020	2019	20
Net Income (Loss) Attributable to ConocoPhillips				
Net interest	$	**(662)**	(604)	(6
Corporate general and administrative expenses		**(200)**	(252)	(
Technology		**(26)**	123	1
Other		**(992)**	771	(1,0
	$	**(1,880)**	38	(1,6

2020 vs. 2019

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest expense increased $58 million in 2020 compared with 2019, primarily due to lower interest income related to lower cash and cash equivalent balances and yield.

Corporate G&A expenses include compensation programs and staff costs. These costs decreased by $52 million in 2020 compared with 2019, primarily due to mark to market adjustments associated with certain compensation programs.

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 decreased by $149 million in 2020 compared with 2019, primarily due to lower 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, ar pension settlement expense. Earnings in "Other" decreased by $1,763 million in 2020 compared with 2019, primarily due to:

- An unrealized loss of $855 million after-tax on our CVE common shares in 2020, compared with a $649 million after-tax unrealized gain in 2019.
- The absence of 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 18—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information related to the 2017 Tax Cut and Jobs Act.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars Except as Indicated		
		2020	2019	
Net cash provided by operating activities	$	**4,802**	11,104	12,
Cash and cash equivalents		**2,991**	5,088	5,
Short-term investments		**3,609**	3,028	
Short-term debt		**619**	105	
Total debt		**15,369**	14,895	14,
Total equity		**29,849**	35,050	32,
Percent of total debt to capital*		**34 %**	30	
Percent of floating-rate debt to total debt		**7 %**	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 2020, the primary uses o our available cash were $4,715 million to support our ongoing capital expenditures and investments program $1,831 million to pay dividends on our common stock; $892 million to repurchase our common stock; and $658 million for net purchase of investments. During 2020, cash and cash equivalents decreased by $2,097 million to $2,991 million.

We entered the year with a strong balance sheet including cash and cash equivalents of over $5 billion, shor term investments of $3 billion, and an undrawn credit facility of $6 billion, totaling approximately $14 billio in available liquidity. This strong foundation allowed us to be measured in our response to the sudden chang in business environment as we exited the first quarter of 2020. In response to the oil market downturn that began in early 2020, we announced the following capital, share repurchase and operating cost reductions. W reduced our 2020 operating plan capital expenditures by a total of $2.3 billion, or approximately thirty-five percent of the original guidance. We suspended our share repurchase program, further reducing cash outlays by approximately $2 billion. We also reduced our operating costs by approximately $0.6 billion, or roughly ten percent of the original 2020 guidance. Collectively, these actions represent a reduction in 2020 cash uses approximately $5 billion versus the original operating plan.

Considering the weakness in oil prices during the second quarter of 2020, we established a framework for evaluating and implementing economic curtailments, which resulted in taking an additional significant step o curtailing production, predominantly from operated North American assets. Due to our strong balance sheet we were in an advantaged position to forgo some production and cash flow in anticipation of receiving highe cash flows for those volumes in the future. Based on our economic criteria, we began restoring production from voluntary curtailments in July, and with oil prices stabilizing around $40 per barrel, we ended our curtailment program by the end of the third quarter.

In the fourth quarter of 2020, we resumed share repurchases, repurchasing $0.2 billion of shares in October, before suspending our share repurchase program upon entry into a definitive agreement to acquire Concho. We resumed share repurchases in February 2021 after completion of our Concho acquisition.

As of December 31, 2020, we had cash and cash equivalents of $3.0 billion, short-term investments of $3.6 billion, and available borrowing capacity under our credit facility of $5.7 billion, totaling over $12 billion of liquidity. 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 mee our funding requirements in the near- and long-term, including our capital spending program, dividend payments and required debt payments.

Significant Changes in Capital

Operating Activities
During 2020, cash provided by operating activities was $4,802 million, a 57 percent decrease from 2019. Th decrease was primarily due to lower realized commodity prices, normal field decline, production curtailmen the divestiture of our U.K. and Australia-West assets, and the absence in 2020 of collections under our settlement agreement with PDVSA, partially offset by lower production and operating expenses.

Our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natu 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 marg 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 1,127 MBOED in 2020. Full-year production excluding Libya averaged 1,118 MBOED in 2020. Adjusting for estimated curtailments of approximately 80 MBOED; closed acquisitions a dispositions; and excluding Libya; production for 2020 was 1,176 MBOED. Production in 2021 is expected be approximately 1.5 MMBOED, reflecting the impact from the Concho acquisition. 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 an 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 cos effective development. While we actively manage these factors, production levels can cause variability in c 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. 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. Our reserve replacement was negative 8 percent in 2020, reflecting the impact of lower prices, which reduced reserves by approximately 600 MMBO Our organic reserve replacement, which excluded a net decrease of 7 MMBOE from sales and purchases, wa negative 84 percent in 2020.

In the three years ended December 31, 2020, our reserve replacement was 59 percent, reflecting the impact o lower prices in 2020. Our organic reserve replacement during the three years ended December 31, 2020, which excluded a net increase of 89 MMBOE related to sales and purchases, was 53 percent.

For additional information about our 2021 capital budget, see the “2021 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 i commodity prices or as more technical data becomes available on reservoirs. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Investing Activities
In 2020, we invested $4.7 billion in capital expenditures, of which $0.5 billion consisted of strategic acquisitions, including additional Montney acreage. Capital expenditures invested in 2019 and 2018 were $ billion and $6.8 billion, respectively. For information about our capital expenditures and investments, see th “Capital Expenditures and Investments” section.

We invest in short-term investments as part of our cash investment strategy, the primary objective of which is to protect principal, maintain liquidity and provide yield and total returns; these investments include time deposits, commercial paper as well as debt securities classified as available for sale. Funds for short-term needs to support our operating plan and provide resiliency to react to short-term price volatility are invested highly liquid instruments with maturities within the year. Funds we consider available to maintain resilienc in longer term price downturns and to capture opportunities outside a given operating plan may be invested i instruments with maturities greater than one year. For additional information, see Note 1–Accounting Polici and Note 13–Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Investing activities in 2020 included net purchases of $658 million of investments, of which $420 million wa invested in short-term instruments and $238 million was invested in long-term instruments. Investing activities in 2019 included net purchases of $2.9 billion of investments, of which $2.8 billion was invested i short-term instruments and $0.1 billion was invested in long-term instruments. For additional information, s Note 13—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Proceeds from asset sales in 2020 were $1.3 billion. We received cash proceeds of $765 million for the divestiture of our Australia-West assets and operations, with another $200 million payment due upon final investment decision of the proposed Barossa development project. We also received proceeds of $359 million and $184 million for the sale of our Niobrara interests and Waddell Ranch interests in the Lower 48, respectively.

Proceeds from asset sales in 2019 were $3.0 billion, including $2.2 billion for the sale of two ConocoPhillips U.K. subsidiaries and $350 million for the sale of our 30 percent interest in the Greater Sunrise Fields. Proceeds from assets sales in 2018 were $1.1 billion, including several non-core assets in the Lower 48, as well as the sale of a ConocoPhillips subsidiary which held 16.5 percent of our 24 percent interest in the Clai Field in the U.K. For additional information on our dispositions, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

<u>*Financing Activities*</u>
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 financ 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. The amount of the facility is not subject to the redetermination prior to its expiration date.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in th 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's ability to issue up to $6.0 billion of commercial paper, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. With $300 million of commercial paper outstanding and no direct borrowings or letters of credit, we had $5.7 billion in available borrowing capacity under the revolving credit facility at December 31, 2020. We may consider issuing additional commercial paper in the future to supplement our cash position.

In October 2020, Moody's affirmed its rating of our senior long-term debt of "A3" with a "stable" outlook, a affirmed its rating of our short-term debt as "Prime-2." In January 2021, Fitch affirmed its rating of our lon term debt as "A" with a "stable" outlook and affirmed its rating of our short-term debt as "F1+." On Januar 25, 2021, S&P revised the industry risk assessment for the E&P industry to 'Moderately High' from

‘Intermediate’ based on a view of increasing risks from the energy transition, price volatility, and weaker profitability. On February 11, 2021, S&P downgraded its rating of our long-term debt from “A” to “A-” wit “stable” outlook and downgraded its rating of our short-term debt from “A-1” to “A-2.” 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, upon downgrade of our credit ratings. If our credit ratings are downgraded from their current levels, 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 th 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 lette of credit as collateral. At December 31, 2020 and 2019, we had direct bank letters of credit of $249 million and $277 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 ma be required to post additional letters of credit.

On January 15, 2021, we completed the acquisition of Concho in an all-stock transaction. In the acquisition, we assumed Concho’s publicly traded debt. On December 7, 2020, we launched an offer to exchange Concho’s publicly traded debt for debt issued by ConocoPhillips. The exchange offer settled on February 8, 2021. Of the approximately $3.9 billion in aggregate principal amount of Concho’s notes subject to the exchange offer, 98 percent, or approximately $3.8 billion, was tendered and exchanged for new debt issued b ConocoPhillips. There were no impacts to ConocoPhillips’ credit ratings as a result of the debt exchange. F additional information, see Note 10—Debt and Note 25—Acquisition of Concho Resources Inc., in the Note to Consolidated Financial Statements.

Shelf Registration

We have a universal shelf registration statement on file with the SEC under which we have the ability to issu and sell an indeterminate amount of various types of debt and equity securities.

Guarantor Summarized Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and Burlington Resourc 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 Compa 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.

In March of 2020, the SEC adopted amendments to simplify the financial disclosure requirements for guarantors and issuers of guaranteed securities registered under Rule 3-10 of Regulation S-X. Based on our evaluation of our existing guarantee relationships, we qualify for the transition to alternative disclosures. W elected early voluntary compliance with the final amendments beginning in the third quarter of 2020. Accordingly, condensed consolidating information by guarantor and issuer of guaranteed securities will no longer be reported, and alternative disclosures of summarized financial information for the consolidated Obligor Group is presented. The following tables present summarized financial information for the Obligor Group, as defined below:

- The Obligor Group will reflect guarantors and issuers of guaranteed securities consisting of ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC.
- Consolidating adjustments for elimination of investments in and transactions between the collective guarantors and issuers of guaranteed securities are reflected in the balances of the summarized financial information.

- Non-Obligated Subsidiaries are excluded from this presentation.

Transactions and balances reflecting activity between the Obligors and Non-Obligated Subsidiaries are presented separately below:

Summarized Income Statement Data

		Millions of Dollars **2020**
Revenues and Other Income	**$**	**8,3**
Income (loss) before income taxes		**(2,9**
Net income (loss)		**(2,7**
Net Income (Loss) Attributable to ConocoPhillips		**(2,7**

Summarized Balance Sheet Data

		Millions of Dollars **December 31, 2020**
Current assets	**$**	**8,5**
Amounts due from Non-Obligated Subsidiaries, current		**4**
Noncurrent assets		**37,1**
Amounts due from Non-Obligated Subsidiaries, noncurrent		**7,7**
Current liabilities		**3,7**
Amounts due to Non-Obligated Subsidiaries, current		**1,3**
Noncurrent liabilities		**18,0**
Amounts due to Non-Obligated Subsidiaries, noncurrent		**3,9**

Capital Requirements

For information about our capital expenditures and investments, see the “Capital Expenditures and Investments” section.

Our debt balance at December 31, 2020, was $15,369 million, an increase of $474 million from the balance December 31, 2019. Maturities of debt (including payments for finance leases) due in 2021 of $601 million excluding net unamortized premiums and discounts, will be paid from current cash balances and cash generated by operations. For more information on Debt, see Note 10—Debt, in the Notes to Consolidated Financial Statements.

We believe in delivering value to our shareholders via a growing and sustainable dividend supplemented by additional returns of capital, including share repurchases. In 2020, we paid $1,831 million, $1.69 per share common stock, in dividends. This is an increase over 2019 and 2018, when we paid $1.34 and $1.16 per sha of common stock, respectively. In February 2021, we announced a quarterly dividend of $0.43 per share, payable March 1, 2021, to stockholders of record at the close of business on February 12, 2021.

In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. Cost of share repurchases were $892 million, $3,500 million and $2,999 million in 2020, 2019 and 2018, respectively. Share repurchases since inception of our current program totaled 189 million shares at a cost of $10,517 million, as of December 31, 2020. In the fourth quarter of 2020, we suspended share repurchases upon entry into a definitive agreement to acquire Concho. We resumed share repurchases in February 2021 after the completion of our Concho acquisition. Repurchases are made at management’s discretion, at prevailing prices, subject to market conditions and oth factors.

Our dividend and share repurchase programs are subject to numerous considerations, including market conditions, management discretion and other factors. See “Item 1A—Risk Factors – Our ability to declare a pay dividends and repurchase shares is subject to certain considerations.”

In addition to the requirements above, we have contractual obligations for the purchase of goods and service of approximately $8,123 million. We expect to fulfill $2,805 million of these obligations in 2021. These figures exclude purchase commitments for jointly owned fields and facilities where we are not the operator. Purchase obligations of $5,237 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG product terminals, to transport, process, treat an store commodities. Purchase obligations of $2,290 million are related to market-based contracts for commodity product purchases with third parties. 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.

Capital Expenditures and Investments

		Millions of Dollars		
		2020	2019	20
Alaska	$	**1,038**	1,513	1,2
Lower 48		**1,881**	3,394	3,1
Canada		**651**	368	4
Europe, Middle East and North Africa		**600**	708	8
Asia Pacific		**384**	584	7
Other International		**121**	8	
Corporate and Other		**40**	61	1
Capital Program	$	**4,715**	6,636	6,7

Our capital expenditures and investments for the three-year period ended December 31, 2020 totaled $18.1 billion. The 2020 expenditures supported key exploration and developments, primarily:

- Development and appraisal in the Lower 48, including Eagle Ford, Permian, 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.
- Development and exploration activities across assets in Norway.
- Appraisal activities in liquids-rich plays and optimization of oil sands development in Canada.
- Continued development activities in China, Malaysia, and Indonesia.
- Exploration activities in Argentina.

2021 CAPITAL BUDGET

In February 2021, we announced 2021 operating plan capital for the combined company of $5.5 billion. The plan includes $5.1 billion to sustain current production and $0.4 billion for investment in major projects, primarily in Alaska, in addition to ongoing exploration appraisal activity.

The operating plan capital budget of $5.5 billion is expected to deliver production from the combined compa of approximately 1.5 MMBOED in 2021. This production guidance excludes Libya.

For information on PUDs and the associated costs to develop these reserves, see the “Oil and Gas Operation 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 acti 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 lov end of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveri We accrue receivables for insurance or other third-party recoveries when applicable. 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 continge liability exposures will exceed current accruals by an amount that would have a material adverse impact on c consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statemen

Legal and Tax Matters

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas roya 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 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 t adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 18—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 regulatio as other companies in our industry. The most significant of these environmental laws and regulations includ 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 Superfund), which imposes liability on generators, transporters and arrangers of hazardous substanc 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, stora 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 discharg 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 respon 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 o hazardous substances and hazardous wastes. They also, in most cases, require permits in association with ne or modified operations. These permits can require an applicant to collect substantial information in connecti 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 law 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 o 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 restriction 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 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 the 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, 2020, 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 part 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 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 att 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 financia condition.

Expensed environmental costs were $393 million in 2020 and are expected to be about $435 million per yea in 2021 and 2022. Capitalized environmental costs were $161 million in 2020 and are expected to be about $210 million per year in 2021 and 2022.

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 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 curre ownership or control of sites. If applicable, we accrue receivables for probable insurance or other third-part 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 uniq 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, 2020, our balance sheet included total accrued environmental costs of $180 million, compared with $171 million at December 31, 2019, 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 o 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 futu 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 material impact on our results of operations and financial condition. Examples of legislation and 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 2020 was approximately $7 million before-tax.
- The Alberta Technology Innovation and Emissions Reduction (TIER) regulation requires any existi facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or equivale per year to meet a facility benchmark intensity. The total cost of these regulations in 2020 was approximately $2 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 o 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 U.S. government 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 2020 was approximately $29 million (net share before-tax). We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia and Alberta operations in Canada, totaling approximately $3.5 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the Unite Nations Framework Convention on Climate Change, setting out a process for achieving global emission reductions. The new administration has recommitted the United States to the Paris Agreement, and a significant number of U.S. state and local governments and major corporations headquartered in the U.S. have also announced related commitments.

In the U.S., some additional form of regulation may be forthcoming in the future at the federal and state leve with respect to GHG emissions. Such regulation could take any of several forms that may result in the creat of additional costs in the form of taxes, the restriction of output, investments of capital to maintain complian 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 througho 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, includi 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 event changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices o our products and services.

Climate Change Litigation
Beginning in 2017, governmental and other entities in several states in the U.S. have filed lawsuits against o and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. Additional lawsuits with similar allegations are expected to be filed. The amounts claimed by plaintiffs are unspecified and the legal and factual issues involved in these cases are unprecedented. ConocoPhillips believes these lawsuits are factually and legally meritless and are an inappropriate vehicle to address the challenges associated with climate change and will vigorously defend against such lawsuits.

Several Louisiana parishes and the State of Louisiana have filed 43 lawsuits under Louisiana's State and Lo Coastal Resources Management Act (SLCRMA) against oil and gas companies, including ConocoPhillips, seeking compensatory damages for contamination and erosion of the Louisiana coastline allegedly caused b historical oil and gas operations. ConocoPhillips entities are defendants in 22 of the lawsuits and will vigorously defend against them. Because Plaintiffs' SLCRMA theories are unprecedented, there is uncertai about these claims (both as to scope and damages) and any potential financial impact on the company.

Company Response to Climate-Related Risks
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 three different scopes. Gross operated Scope 1 and Scope 2 GHG emissions help us understand our 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 w consume.

Scope 3 emissions are indirect emissions from sources that we neither own nor control.

We announced in October 2020 the adoption of a Paris-aligned climate risk framework with the objective of implementing a coherent set of choices designed to facilitate the success of our existing exploration and production business through the energy transition. Given the uncertainties remaining about how the energy transition will evolve, the strategy aims to be robust across a range of potential future outcomes.

The strategy is comprised of four pillars:

- Targets: Our target framework consists of a hierarchy of targets, from a long-term ambition that sets the direction and aim of the strategy, to a medium-term performance target for GHG emissions intensity, to shorter-term targets for flaring and methane intensity reductions. These performance targets are supported by lower-level internal business unit goals to enable the company to achieve th company-wide targets. We have set a target to reduce our gross operated (scope 1 and 2) emissions intensity by 35 to 45 percent from 2016 levels by 2030, with an ambition to achieve net-zero operate emissions by 2050. We have joined the World Bank Flaring Initiative to work towards zero routine flaring of gas by 2030.
- Technology choices: We expanded our Marginal Abatement Cost Curve process to provide a broader range of opportunities for emission reduction technology.
- Portfolio choices: Our corporate authorization process requires all qualifying projects to include a GHG price in their project approval economics. Different GHG prices are used depending on the region or jurisdiction. Projects in jurisdictions with existing GHG pricing regimes incorporate the existing GHG price and forecast into their economics. Projects where no existing GHG pricing regime exists utilize a scenario forecast from our internally consistent World Energy Model. In this way, both existing and emerging regulatory requirements are considered in our decision-making. T company does not use an estimated market cost of GHG emissions when assessing reserves in jurisdictions without existing GHG regulations.
- External engagement: Our external engagement aims to differentiate ConocoPhillips within the oil a gas sector with our approach to managing climate-related risk. We are 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.

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 o deferred tax asset valuation allowances in this report, address all important accounting areas where the natur of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary t 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 ga industry. The acquisition of G&G seismic information, prior to the discovery of proved reserves, is expense 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 explorati and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercise 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 adjust prospectively.

At year-end 2020, the remaining $2.4 billion of net capitalized unproved property costs consisted primarily o 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, approximatel $1.9 billion is concentrated in 10 major development areas, the majority of which are not expected to move t proved properties in 2021. 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, pendi 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 capitaliz 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, b 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 i 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 bee 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 developmen plans or seek environmental permitting. Once a determination is made the well did not encounter potentiall economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expens

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 2020, total suspended well costs were $682 million, compared with $1,020 million at year-end 2019. For additional information on suspended wells, including an aging analysis, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial

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 thes 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 change 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 reach the end of its economi life is based on 12-month average prices and current costs. This date estimates when production will end and 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; recoverabl operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of co 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 2020, the net book value of productive PP&E subject to a unit-of-production calculation was approximately $33 billion and the DD&A recorded on these assets in 2020 was approximately $5.3 billion. The estimated proved developed reserves for our consolidate operations were 3.2 billion BOE at the end of 2019 and 2.5 billion BOE at the end of 2020. If the estimates proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2020 would have increased by an estimated $588 million.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstanc indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. there is an indication the carrying amount of an asset may not be recovered, a recoverability test is performe using management's assumptions for prices, volumes and future development plans. If, upon review, the su of the undiscounted cash flows before income-taxes is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as impairments in the periods in which th determination 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 fo 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 and prices 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 a related fair value calculations are based on estimated future production volumes, commodity prices, operatin costs and capital decisions, considering all available information at the date of review. Differing assumptior could affect the timing and the amount of an impairment in any period. See Note 8—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred. Such evidence of a lo 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 carryin amount. When such a condition is judgmentally determined to be other than temporary, an impairment char 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 fai value is typically based on the present value of expected future cash flows using discount rates and prices believed to be consistent with those used by principal market participants, plus market analysis of comparab assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount o an impairment of an investment in any period. See the "APLNG" section of Note 5—Investments, Loans ar 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 ga platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair value of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP& at the time of installation of the asset based on estimated discounted costs. Fair value is estimated using a present value approach, incorporating assumptions about estimated amounts and timing of settlements and impacts of the use of technologies. Estimating future asset removal costs requires significant judgement. M of these removal obligations are many years, or decades, in the future and the contracts and regulations ofter have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. The carrying value of our asset retirement obligation estimate is sensitive to inputs such as asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and oth inputs into valuation of the obligation, including discount and inflation rates, which are all subject to change between the time of initial recognition of the liability and future settlement of our obligation.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreas to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations 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 properti

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we ha 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 9- 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 a 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, futu 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 projecte 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 determinati 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 und 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 $1,200 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 $110 million, while a 100 basis-point decrease in the return on plan assets assumption would increase annua benefit expense by $80 million. In determining the discount rate, we use yields on high-quality fixed incom 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 of their future services for a significant number of employees, we could recognize a curtailment gain or loss. See Note 17—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 liabilit shared with other responsible parties. Estimated future costs related to contingencies are subject to change a 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 “Capi Resources and Liquidity” and Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Income Taxes

We are subject to income taxation in numerous jurisdictions worldwide. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess our deferred tax assets and reduce such assets a valuation allowance if we deem it is more likely than not that some portion, or all, of the deferred tax asset will not be realized. In assessing the need for adjustments to existing valuation allowances, we consider all available positive and negative evidence. Positive evidence includes reversals of temporary differences, forecasts of future taxable income, assessment of future business assumptions and applicable tax planning strategies that are prudent and feasible. Negative evidence includes losses in recent years as well as the forecasts of future net income (loss) in the realizable period. In making our assessment regarding valuation allowances, we weight the evidence based on objectivity. Numerous judgments and assumptions are inheren in the determination of future taxable income, including factors such as future operating conditions and the assessment of the effects of foreign taxes on our U.S. federal income taxes (particularly as related to prevail oil and gas prices). See Note 18—Income Taxes for additional information, in the Notes to Consolidated Financial Statements.

We regularly assess and, if required, establish accruals for uncertain tax positions that could result from assessments of additional tax by taxing jurisdictions in countries where we operate. We recognize a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. These accruals for uncertain tax positions are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, court proceedings, changes applicable tax laws, including tax case rulings and legislative guidance, or expiration of the applicable statut of limitations. See Note 18—Income Taxes for additional information, in the Notes to Consolidated Financi Statements.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE “SAFE HARBOR” PROVISIONS O 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, objectives of management for future operations, the anticipated benefits of the transaction between us and Concho, the anticipated impact of the transaction on the combined company’s business and future financial and operating results, the expected amount and the timing of synergies from the transaction 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,” “believe,” “budget,” “continue,” “could,” “effort,” “estimate,” “expect,” “forecast,” “intend,” “goal,” “guidance,” “may,” “objective,” “outlook,” “plan,” “potential,” “predict,” “projection,” “seek,” “should,” “target,” “will,” “would” 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 b incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forwar 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 and uncertainties, including, but n limited to, the following:

- The impact of public health crises, including pandemics (such as COVID-19) and epidemics and an related company or government policies or actions.
- Global and regional changes in the demand, supply, prices, differentials or other market conditions affecting oil and gas, including changes resulting from a public health crisis or from the imposition lifting of crude oil production quotas or other actions that might be imposed by OPEC and other producing countries and the resulting company or third-party actions in response to such changes.
- Fluctuations in crude oil, bitumen, natural gas, LNG and NGLs prices, including a prolonged declin 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, whi may result in recognition of impairment charges on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Potential failures or delays in achieving expected reserve or production levels from existing and futu 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 commodi 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& 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 ga 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 o

announced and future E&P 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, 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, includi as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under existing and 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 regulato measures to limit or reduce GHG emissions.
- Liability resulting from litigation, including the potential for litigation related to the transaction with Concho, or our failure to comply with applicable laws and regulations.
- General domestic and international economic and political developments, including armed hostilitie expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and NGLs pricing; regulation or taxation; 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.
- 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 or investment sentiment.
- Our inability to execute, or delays in the completion, of any asset dispositions or acquisitions we ele to pursue.
- Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for pending or future asset dispositions or acquisitions, or that such approvals may require modification to the term of the transactions or the operation of our remaining business.
- Potential disruption of our operations as a result of pending or future asset dispositions or acquisitic including the diversion of management time and attention.
- Our inability to deploy the net proceeds from any asset dispositions that are pending or that we elec undertake in the future 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 capital expenditure reductions.
- The inadequacy of storage capacity for our products, and ensuing curtailments, whether voluntary o involuntary, required to mitigate this physical constraint.
- Our ability to successfully integrate Concho's business.
- The risk that the expected benefits and cost reductions associated with the transaction with Concho may not be fully achieved in a timely manner, or at all.
- The risk that we will be unable to retain and hire key personnel.
- Unanticipated difficulties or expenditures relating to integration with Concho.
- Uncertainty as to the long-term value of our common stock.
- The diversion of management time on integration-related matters.
- The factors generally described in Item 1A—Risk Factors in this 2020 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 o cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. W 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 Boa of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficien 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 th 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 t 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 th balance sheet at December 31, 2020, 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, 2020 and 2019, 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 expecte 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. A hypothetical 10 percent change in prevailing interest rates would not have a material impact on interest expense associated with our floating-ra debt. The fair value of the fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data. Changes to prevailing interest rates would not impact our cashflows associate with fixed rate debt, unless we elect to repurchase or retire such debt prior to maturity.

	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Avera Inter R
Year-End 2020				
2021	**$ 133**	**8.47 %**	**$ 300**	**0.**
2022	**346**	**2.53**	**500**	**1.**
2023	**110**	**7.03**	**-**	
2024	**459**	**3.51**	**-**	
2025	**368**	**5.33**	**-**	
Remaining years	**11,793**	**6.28**	**283**	**0.**
Total	**$ 13,209**		**$ 1,083**	
Fair value	**$ 18,023**		**$ 1,083**	
Year-End 2019				
2020	$ -	- %	$ -	
2021	140	6.24	-	
2022	343	2.54	500	2.
2023	106	7.20	-	
2024	456	3.52	-	
Remaining years	12,143	6.25	283	1.
Total	$ 13,188		$ 783	
Fair value	$ 17,325		$ 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 selectiv hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or lo 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, 2020 and 2019, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps for purposes of mitigating our cash-related exposures. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we electe 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, 2020, we had outstanding foreign currency exchange forward contracts to sell $0.45 billio CAD at $0.748 CAD against the U.S. dollar. 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. Based on the assumed volatility in the fair value calculation, the net fair value of these foreign currency contracts at December 31, 2020 and December 31, 2019, were a before-tax loss of $16 million and $28 million, respectively. Based on an adverse hypothetical 10 percent change in the December 2020 and December 201 exchange rate, this would result in an additional before-tax loss of $39 million and $115 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 ma be correlated.

The gross notional and fair value of these positions at December 31, 2020 and 2019, were as follows:

Foreign Currency Exchange Derivatives		In Millions			
		Notional		Fair Value*	
		2020	2019	**2020**	20
Sell Canadian dollar, buy U.S. dollar	CAD	**450**	1,350	**(16)**	(
Buy Canadian dollar, sell U.S. dollar	CAD	**80**	13	**2**	
Sell British pound, buy euro	GBP	**8**	-	**-**	
Buy British pound, sell euro	GBP	**3**	4	**-**	

**Denominated in USD.*

For additional information about our use of derivative instruments, see Note 13—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

Reports of Management

Management prepared, and is responsible for, the consolidated financial statements and the other informatio 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 statemen preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2020. In making this assessment, it used the criteria set forth by the Committee of Sponsorin Organizations of the Treadway Commission in *Internal Control—Integrated Framework (2013).* Based on assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2020.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as December 31, 2020, and their report is included herein.

/s/ Ryan M. Lance	/s/ William L. Bullock, Jr.
Ryan M. Lance	**William L. Bullock, Jr.**
Chairman and Chief Executive Officer	Executive Vice President and Chief Financial Officer

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, 2020 and 2019, 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, 2020, and the related notes (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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with U.S. generally accept 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, 2020 based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsor Organizations of the Treadway Commission (2013 framework) and our report dated February 16, 2021, 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 an 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 th 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 opinio

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 financ statements and (2) involved our especially challenging, subjective or complex judgments. The communicati of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on 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, 2020, the asset retirement obligation (ARO) balance totaled $5.6 billion. As further described in Note 9, 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 certain obligations related to deepwater 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 ma result in a material impact to earnings given the relatively short remaining useful lives 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 eff 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 Company's methodology to estimate removal costs.

Depreciation, depletion and amortization and impairment of properties, plants and equipment

Description of the Matter

At December 31, 2020, the net book value of the Company's properties, plants and equipment (PP&E) was $39.9 billion, and depreciation, depletion and amortization (DD&A) expense and impairment expense were $5.5 billion and $0.8 billion, respectively, for the year then ended. As described in Note 1, under the successful effo method of accounting, DD&A of PP&E on producing hydrocarbon properties and cert pipeline and liquified natural gas assets (those which are expected to have a declining utilization pattern) are determined by the unit-of-production method. The unit-of-production method uses proved oil and gas reserves, as estimated by the Company's internal reservoir engineers. PP&E used in operations is assessed by management for impairment when changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If the is an indication the carrying value of an asset may not be recovered, the Company compares undiscounted cash flows before income taxes to the carrying value of the as group. If the expected undiscounted cash flows before income taxes are lower than the carrying value of the asset group, the carrying value is written down to estimated fair value.

Proved oil and gas reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extractio recovery and processing yield factors, installed plant operating capacity and approved operating limits. Additionally, the expected future cash flows used for impairment reviews and related fair value calculations are based on future production volumes of estimated oil and gas reserves. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection of input 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 an independent petroleum engineering consulting firm to perform a review of the processes and controls used by Company's internal reservoir engineers to determine estimates of proved oil and gas reserves.

Auditing the Company's DD&A and impairment calculations is complex because of th use of the work of the internal reservoir engineers and the independent petroleum engineering consulting firm and the evaluation of management's determination of the inputs described above used by the internal reservoir engineers in estimating oil and ga 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 processes to calculate DD&A and impairments, including management's controls over the completeness and accurac of the financial data provided to the internal reservoir engineers for use in estimating o and gas reserves.

Our audit procedures included, among others, evaluating the professional qualification and objectivity of the Company's internal reservoir engineers primarily responsible fo overseeing the preparation of the reserve estimates and the independent petroleum engineering consulting 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, evaluated the completeness and accuracy of the financial data and inputs described abo used by the internal reservoir engineers in estimating oil and gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the accuracy of the DD&A and impairment calculations, including comparing the oil and gas reserve amounts used in the calculations to the Company's reserve report.

/s/ Ernst & Young LLP
We have served as ConocoPhillips' auditor since 1949.
Houston, Texas
February 16, 2021

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, 2020, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizatio of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, ConocoPhillips (the Compar maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (Unit States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flo for each of the three years in the period ended December 31, 2020, and the related notes and our report dated February 16, 2021, 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 "Reports of Management." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our auc We are a public accounting firm registered with the PCAOB and are required to be independent with respect to th 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 anc 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 or 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 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 misstatemen Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may beco 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 16, 2021

Consolidated Income Statement				**ConocoPhill**
Years Ended December 31		Millions of Dollars		
		2020	2019	20
Revenues and Other Income				
Sales and other operating revenues	$	**18,784**	32,567	36,4
Equity in earnings of affiliates		**432**	779	1,0
Gain on dispositions		**549**	1,966	1,0
Other income (loss)		**(509)**	1,358	1
Total Revenues and Other Income		**19,256**	36,670	38,7
Costs and Expenses				
Purchased commodities		**8,078**	11,842	14,2
Production and operating expenses		**4,344**	5,322	5,2
Selling, general and administrative expenses		**430**	556	4
Exploration expenses		**1,457**	743	3
Depreciation, depletion and amortization		**5,521**	6,090	5,9
Impairments		**813**	405	
Taxes other than income taxes		**754**	953	1,0
Accretion on discounted liabilities		**252**	326	3
Interest and debt expense		**806**	778	7
Foreign currency transaction (gains) losses		**(72)**	66	(
Other expenses		**13**	65	3
Total Costs and Expenses		**22,396**	27,146	28,7
Income (loss) before income taxes		**(3,140)**	9,524	9,9
Income tax provision (benefit)		**(485)**	2,267	3,6
Net income (loss)		**(2,655)**	7,257	6,3
Less: net income attributable to noncontrolling interests		**(46)**	(68)	(
Net Income (Loss) Attributable to ConocoPhillips	$	**(2,701)**	7,189	6,2
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic	$	**(2.51)**	6.43	5.
Diluted		**(2.51)**	6.40	5.
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,078,030**	1,117,260	1,166,4
Diluted		**1,078,030**	1,123,536	1,175,5

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income — ConocoPhill

Years Ended December 31		Millions of Dollars 2020	2019	20
Net Income (Loss)	**$**	**(2,655)**	7,257	6,3
Other comprehensive income (loss)				
Defined benefit plans				
Prior service credit (cost) arising during the period		**29**	-	
Reclassification adjustment for amortization of prior service credit included in net income (loss)		**(32)**	(35)	(
Net change		**(3)**	(35)	(
Net actuarial loss arising during the period		**(210)**	(55)	(1
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)		**117**	146	2
Net change		**(93)**	91	1
Nonsponsored plans*		**1**	(3)	
Income taxes on defined benefit plans		**20**	(2)	(
Defined benefit plans, net of tax		**(75)**	51	
Unrealized holding gain on securities		**2**	-	
Unrealized gain on securities, net of tax		**2**	-	
Foreign currency translation adjustments		**209**	699	(6
Income taxes on foreign currency translation adjustments		**3**	(4)	
Foreign currency translation adjustments, net of tax		**212**	695	(6
Other Comprehensive Income (Loss), Net of Tax		**139**	746	(6
Comprehensive Income (Loss)		**(2,516)**	8,003	5,7
Less: comprehensive income attributable to noncontrolling interests		**(46)**	(68)	(
Comprehensive Income (Loss) Attributable to ConocoPhillips	**$**	**(2,562)**	7,935	5,6

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhil**

At December 31		Millions of Dollars	
		2020	2
Assets			
Cash and cash equivalents	$	**2,991**	5,0
Short-term investments		**3,609**	3,0
Accounts and notes receivable (net of allowance of $4 and $13, respectively)		**2,634**	3,2
Accounts and notes receivable—related parties		**120**	1
Investment in Cenovus Energy		**1,256**	2,1
Inventories		**1,002**	1,0
Prepaid expenses and other current assets		**454**	2,2
Total Current Assets		**12,066**	16,9
Investments and long-term receivables		**8,017**	8,6
Loans and advances—related parties		**114**	2
Net properties, plants and equipment (net of accumulated DD&A of $62,213 and $55,477, respectively)		**39,893**	42,2
Other assets		**2,528**	2,4
Total Assets	$	**62,618**	70,5
Liabilities			
Accounts payable	$	**2,669**	3,1
Accounts payable—related parties		**29**	
Short-term debt		**619**	1
Accrued income and other taxes		**320**	1,0
Employee benefit obligations		**608**	6
Other accruals		**1,121**	2,0
Total Current Liabilities		**5,366**	7,0
Long-term debt		**14,750**	14,7
Asset retirement obligations and accrued environmental costs		**5,430**	5,3
Deferred income taxes		**3,747**	4,6
Employee benefit obligations		**1,697**	1,7
Other liabilities and deferred credits		**1,779**	1,8
Total Liabilities		**32,769**	35,4
Equity			
Common stock (2,500,000,000 shares authorized at $0.01 par value)			
Issued (2020—1,798,844,267 shares; 2019—1,795,652,203 shares)			
Par value		**18**	
Capital in excess of par		**47,133**	46,9
Treasury stock (at cost: 2020—730,802,089 shares; 2019—710,783,814 shares)		**(47,297)**	(46,4
Accumulated other comprehensive loss		**(5,218)**	(5,3
Retained earnings		**35,213**	39,7
Total Common Stockholders' Equity		**29,849**	34,9
Noncontrolling interests		**-**	
Total Equity		**29,849**	35,0
Total Liabilities and Equity	$	**62,618**	70,5

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows | **ConocoPhilli**

Years Ended December 31		Millions of Dollars		
		2020	2019	20
Cash Flows From Operating Activities				
Net income (loss)	$	**(2,655)**	7,257	6,30
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization		**5,521**	6,090	5,95
Impairments		**813**	405	2
Dry hole costs and leasehold impairments		**1,083**	421	9
Accretion on discounted liabilities		**252**	326	35
Deferred taxes		**(834)**	(444)	28
Undistributed equity earnings		**645**	594	15
Gain on dispositions		**(549)**	(1,966)	(1,06
Unrealized (gain) loss on investment in Cenovus Energy		**855**	(649)	43
Other		**43**	(351)	(24
Working capital adjustments				
Decrease in accounts and notes receivable		**521**	505	23
Decrease (increase) in inventories		**(25)**	(67)	8
Decrease (increase) in prepaid expenses and other current assets		**76**	37	(5
Decrease in accounts payable		**(249)**	(378)	(5
Increase (decrease) in taxes and other accruals		**(695)**	(676)	42
Net Cash Provided by Operating Activities		**4,802**	11,104	12,93
Cash Flows From Investing Activities				
Capital expenditures and investments		**(4,715)**	(6,636)	(6,75
Working capital changes associated with investing activities		**(155)**	(103)	(6
Proceeds from asset dispositions		**1,317**	3,012	1,08
Net sales (purchases) of investments		**(658)**	(2,910)	1,62
Collection of advances/loans—related parties		**116**	127	11
Other		**(26)**	(108)	15
Net Cash Used in Investing Activities		**(4,121)**	(6,618)	(3,84
Cash Flows From Financing Activities				
Issuance of debt		**300**	-	
Repayment of debt		**(254)**	(80)	(4,99
Issuance of company common stock		**(5)**	(30)	12
Repurchase of company common stock		**(892)**	(3,500)	(2,99
Dividends paid		**(1,831)**	(1,500)	(1,36
Other		**(26)**	(119)	(12
Net Cash Used in Financing Activities		**(2,708)**	(5,229)	(9,35
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash		**(20)**	(46)	(11
Net Change in Cash, Cash Equivalents and Restricted Cash		**(2,047)**	(789)	(38
Cash, cash equivalents and restricted cash at beginning of period		**5,362**	6,151	6,53
Cash, Cash Equivalents and Restricted Cash at End of Period	$	**3,315**	5,362	6,15

Restricted cash of $94 million and $230 million is included in the "Prepaid expenses and other current assets" and "Other assets" lines, respectively, of our Consolidated Balance Sheet as of December 31, 2020.
Restricted cash of $90 million and $184 million is included in the "Prepaid expenses and other current assets" and "Other assets" lines, respectively, of our Consolidated Balance Sheet as of December 31, 2019.
See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Equity

Cor

	Millions of Dollars						
	Attributable to ConocoPhillips						
	Common Stock						
		Par Value	Capital in Excess of Par	Treasury Stock	Accum. Other Comprehensive Income (Loss)	Retained Earnings	No Controlli Interes
Balances at December 31, 2017	$	18	46,622	(39,906)	(5,518)	29,391	19
Net income						6,257	4
Other comprehensive loss					(603)		
Dividends paid ($1.16 per share of common stock)						(1,363)	
Repurchase of company common stock				(2,999)			
Distributions to noncontrolling interests and other							(12
Distributed under benefit plans			257				
Changes in Accounting Principles*					58	(278)	
Other						3	
Balances at December 31, 2018	$	18	46,879	(42,905)	(6,063)	34,010	12
Net income						7,189	6
Other comprehensive income					746		
Dividends paid ($1.34 per share of common stock)						(1,500)	
Repurchase of company common stock				(3,500)			
Distributions to noncontrolling interests and other							(12
Distributed under benefit plans			104				
Changes in Accounting Principles**					(40)	40	
Other						3	
Balances at December 31, 2019	$	18	46,983	(46,405)	(5,357)	39,742	6
Net income (loss)						**(2,701)**	**4**
Other comprehensive income					**139**		
Dividends paid ($1.69 per share of common stock)						**(1,831)**	
Repurchase of company common stock				**(892)**			
Distributions to noncontrolling interests and other							**(3**
Disposition							**(8**
Distributed under benefit plans			**150**				
Other						**3**	
Balances at December 31, 2020	**$**	**18**	**47,133**	**(47,297)**	**(5,218)**	**35,213**	

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

***Cumulative effect of the adoption of ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income."*

See Notes to Consolidated Financial Statements.

Note 1—Accounting Policies

- **Consolidation Principles and Investments**—Our consolidated financial statements include the accoun 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 o similar investment of the same issuer. Undivided interests in oil and gas joint ventures, pipelines, natura 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; Low 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. For additiona information, see Note 24—Segment Disclosures and Related Information.

  The unrealized (gain) loss on investment in Cenovus Energy included on our consolidated statement of cash flows, previously reflected on the line item "Other" within net cash provided by operating activitie has been reclassified in the comparative periods to conform with the current period's presentation.

- **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 a 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 le 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 ou 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 o less.

  Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and s of inventory with the same counterparty are entered into "in contemplation" of one another, are combin 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 cos 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 tha one year as of the balance sheet date. They are carried at fair value and presented within the "Investmer 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 wit 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 th FIFO method, consistent with industry practice.

- **Fair Value Measurements**—Assets and liabilities measured at fair value and required to be categorize 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-corroborate inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modificatio 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 t fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivativ not accounted for as hedges are recognized immediately in earnings. We do not apply hedge accounting on our derivative instruments.

- **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 i 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 cost 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 th 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 plar 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 prove 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 7—Suspended Wells and 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 underlyin assets.

- **Depreciation and Amortization**—Depreciation and amortization of PP&E on producing hydrocarbon properties and SAGD facilities 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. If there is an indication the carrying amount of an asset may not be recovered, a recoverability test is performed using management's assumptions such as for prices, volumes and future development plans. If, upon review, the sum of the undiscounted cash flows before income-taxes is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment in the period 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 th 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 typical determined based on the present values of expected future cash flows using discount rates and prices 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 basec on estimated future production volumes, prices and costs, considering all available evidence at the date c 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 ar assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred. 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 and prices 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 relate accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain on dispositions" lir 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). Fair value is estimated using a present value approach, incorporating assumptions about estimated amounts and timing of settlements and impacts of the use of technologies. 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, w 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 9—Asset Retirement Obligations ar 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 through a 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 whe 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 relieve 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 c 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, whethe 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 penaltie 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 lo 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. 2016-13, "Measurement of Credit Losses on Financial Instruments," (ASC Topic 326) and its amendments, beginning January 1, 2020. This ASU, as amended, sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments measured at amortized cost basis based on expected losses rather than incurred losses. This ASU as amended, which primarily applies to our accounts receivable, also requires credit losses related to availab for-sale debt securities to be recorded through an allowance for credit losses. The adoption of this ASU did not have a material impact to our financial statements. The majority of our receivables are due within 30 day or less. We monitor the credit quality of our counterparties through review of collections, credit ratings, and other analyses. We develop our estimated allowance for credit losses primarily using an aging method and analyses of historical loss rates as well as consideration of current and future conditions that could impact ou counterparties' credit quality and liquidity.

Note 3—Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2020	20
Crude oil and natural gas	$	**461**	47
Materials and supplies		**541**	55
	$	**1,002**	1,02

Inventories valued on the LIFO basis totaled $282 million and $286 million at December 31, 2020 and 2019 respectively. In the first quarter of 2020, we recorded a lower of cost or market adjustment of $228 million t our crude oil and natural gas inventories, which is included in the "Purchased commodities" line on our consolidated income statement. Commodity prices have since improved. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $87 million and $155 million at December 31, 2020 and 2019, respectively.

Note 4—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 and payments are included in the "Cash Flows From Investing Activities" section of our consolidated statement of cash flows.

On January 15, 2021, we completed our acquisition of Concho Resources Inc. (Concho), an independent oil and gas exploration and production company with operations across New Mexico and West Texas focused in the Permian Basin. Total consideration for the all-stock transaction was valued at $13.1 billion, in which 1.4 shares of ConocoPhillips common stock was exchanged for each outstanding share of Concho common stoc resulting in the issuance of approximately 286 million shares of ConocoPhillips common stock. We assumed $3.9 billion in aggregate principal amount of outstanding debt for Concho, which was recorded at f value of $4.7 billion as of the closing date. For additional information related to this transaction, see Note 25—Acquisition of Concho Resources Inc.

<u>*2020*</u>

Asset Acquisition

In August 2020, we completed the acquisition of additional Montney acreage in Canada from Kelt Exploratio Ltd. for $382 million after customary adjustments, plus the assumption of $31 million in financing obligation associated with partially owned infrastructure. This acquisition consisted primarily of undeveloped properti and included 140,000 net acres in the liquids-rich Inga Fireweed asset Montney zone, which is directly adjacent to our existing Montney position. The transaction increased our Montney acreage position to approximately 295,000 net acres with a 100 percent working interest. This agreement was accounted for as asset acquisition resulting in the recognition of $490 million of PP&E; $77 million of ARO and accrued environmental costs; and $31 million of financing obligations recorded primarily to long-term debt. Results operations for the Montney asset are reported in our Canada segment.

Assets Sold

In February 2020, we sold our Waddell Ranch interests in the Permian Basin for $184 million after customar adjustments. No gain or loss was recognized on the sale. Results of operations for the Waddell Ranch interests sold were reported in our Lower 48 segment.

In March 2020, we completed the sale of our Niobrara interests for approximately $359 million after customary adjustments and recognized a before-tax loss on disposition of $38 million. At the time of disposition, our interest in Niobrara had a net carrying value of $397 million, consisting primarily of

$433 million of PP&E and $34 million of ARO. The before-tax losses associated with our interests in Niobrara, including the loss on disposition noted above and an impairment of $386 million recorded when w signed an agreement to sell our interests in the fourth quarter of 2019, were $25 million and $372 million for the years ended December 31, 2020 and 2019, respectively. The before-tax earnings associated with our interests in Niobrara for the year ended December 31, 2018 was $35 million. Results of operations for the Niobrara interests sold were reported in our Lower 48 segment.

In May 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations, and based on an effective date of January 1, 2019, we received proceeds of $765 million with an additional $200 million due upon final investment decision of the proposed Barossa development project. W recognized a before-tax gain of $587 million related to this transaction in 2020. At the time of disposition, the net carrying value of the subsidiaries sold was approximately $0.2 billion, excluding $0.5 billion of cash. Th net carrying value consisted primarily of $1.3 billion of PP&E and $0.1 billion of other current assets offset $0.7 billion of ARO, $0.3 billion of deferred tax liabilities, and $0.2 billion of other liabilities. The before-tax earnings associated with the subsidiaries sold, including the gain on disposition noted above, were $851 million, $372 million and $364 million for the years ended December 31, 2020, 2019 and 2018, respectively Production from the beginning of the year through the disposition date in May 2020 averaged 43 MBOED. Results of operations for the subsidiaries sold were reported in our Asia Pacific segment.

2019

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 were reported in our Lower 48 segment. See Note 14—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 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, including the gain on dispositions noted above, were $2.1 billion and $0.9 billion for the years ended December 31, 2019 and 2018, respectively. Results of operations for the U.K. were reported within our Europe, Middle East 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 segment.

In the fourth quarter of 2019, we sold our interests in the Magnolia field and platform for net proceeds of $1 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 associated ARO. The Magnolia results of operations were reported with our Lower 48 segment.

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 an impairment of $87 million in 2018 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 loss associated with our interests in the Barnett, including both the impairment and loss on disposition noted above, was $59 million for the year ended December 31, 2018. Th Barnett results of operations were 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 (Kupar 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 percent interest in th Clair Field, including the recognized gain, were $748 million. Results of operations for our interest in the Cl Field are reported within our Europe, Middle East and North Africa segment and the Kuparuk Assets were 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 1 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.

Note 5—Investments, Loans and Long-Term Receivables

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

		Millions of Dollars	
		2020	20
Equity investments	$	**7,596**	8,23
Loans and advances—related parties		**114**	21
Long-term receivables		**137**	24
Long-term investments in debt securities		**217**	13
Other investments		**67**	7
	$	**8,131**	8,90

Equity Investments
Affiliated companies in which we had a significant equity investment at December 31, 2020, 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 expor LNG.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of Qata 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		
		2020	2019	20
Revenues	$	**7,931**	11,310	11,65
Income before income taxes		**1,843**	3,726	3,66
Net income		**1,426**	3,085	3,24

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

		Millions of Dollars	
		2020	20
Current assets	$	**2,579**	3,28
Noncurrent assets		**35,257**	38,90
Current liabilities		**2,110**	2,60
Noncurrent liabilities		**18,099**	22,16

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, 2020, retained earnings included $41 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,076 million, $1,378 million and $1,226 million in 2020, 2019 and 2018, respectively.

APLNG
APLNG is a joint venture focused on producing CBM from the Bowen and Surat basins in Queensland, Australia. Natural gas is sold to domestic customers and LNG is processed and exported to Asia Pacific markets. 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, a 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 fo approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. All amounts were 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 203

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 t 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 projec finance debt, APLNG made voluntary repayments of $2.2 billion and $1.0 billion to a syndicate of Australia and international commercial banks and the Export-Import Bank of China, respectively.

At December 31, 2020, a balance of $6.2 billion was outstanding on the facilities. See Note 11—Guarantees for additional information.

During the fourth quarter of 2020, the estimated fair value of our investment in APLNG declined to an amou below carrying value, primarily due to the weakening of the U.S. dollar relative to the Australian dollar. Bas on a review of the facts and circumstances surrounding this decline in fair value, we concluded the impairme was not other than temporary under the guidance of FASB ASC Topic 323, "Investments – Equity Method a Joint Ventures." In reaching this conclusion, we primarily considered: (1) the volatility and uncertainty in commodity and exchange rate markets; (2) the intent and ability of ConocoPhillips to retain our investment i APLNG; and (3) the short length of time and extent to which fair value has been less than carrying value (fai value exceeded carrying value as of September 30, 2020). Fair value has been estimated based on an interna discounted cash flow model using the following estimated assumptions: estimated future production, an outlook of future prices from a combination of exchanges (short-term) coupled with pricing service compani and our internal outlook (long-term), operating and capital expenditures, a market outlook of foreign exchang rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants.

At December 31, 2020, the fair value of our investment in APLNG was estimated to be $6,560 million, resulting in a not other than temporary impairment of $112 million. We will continue to monitor the relationship between the carrying value and fair value of APLNG. Should we determine in the future there h been a loss in the value of our investment that is other than temporary, we would record an impairment of ou equity investment, calculated as the total difference between carrying value and fair value as of the end of the reporting period.

At December 31, 2020, the carrying value of our equity method investment in APLNG was $6,672 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $6,242 million, resulting in a basis difference of $430 million on our books. The basis difference, which is substantially 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 2020, 2019 and 2018 was after-tax expense of $41 million, $36 million and $44 million, respectively, representing the amortization of this basis difference on currently producing licenses.

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 $220 million as described below under "Loans and Long-Term Receivables." At December 31, 2020, the book value of our equity method investment in QG3, excluding the project financing, was $742 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 4—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, 2020, significant loans to affiliated companies include $220 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 6—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 issue and outstanding Cenovus Energy common stock. 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 the closing date.

At December 31, 2020, the investment included on our consolidated balance sheet was $1.26 billion and is carried at fair value. The fair value of the 208 million Cenovus Energy common shares reflects the closing price of $6.04 per share on the NYSE on the last trading day of the quarter, a decrease of $855 million from fair value of $2.11 billion at December 31, 2019. The decrease in fair value resulted in a net unrealized loss recorded within the "Other income (loss)" line of our consolidated income statement for the year ended December 31, 2020 relating to the shares held at the reporting date. For the years ended 2019 and 2018, we recorded an unrealized gain of $649 million and an unrealized loss of $437 million, respectively. See Note 14—Fair Value Measurement and Note 21—Other Financial Information, for additional information. Subjec to market conditions, we intend to decrease our investment over time through market transactions, private agreements or otherwise.

On January 4, 2021, Cenovus Energy completed its all-stock acquisition of Husky Energy Inc. As a result of this transaction, our investment now approximates 10 percent of the issued and outstanding Cenovus Energy common stock.

Note 7—Suspended Wells and Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2020, 2019 and 2018

		Millions of Dollars		
		2020	2019	20
Beginning balance at January 1	$	**1,020**	856	85
Additions pending the determination of proved reserves		**164**	239	14
Reclassifications to proved properties		**(42)**	(11)	(3
Sales of suspended wells		**(313)**	(54)	(9
Charged to dry hole expense		**(147)**	(10)	(
Ending balance at December 31	$	**682**	1,020 *	85

Includes $313 million of assets held for sale in Australia at December 31, 2019.
For additional details on suspended wells charged to dry hole expense, see the Exploration Expenses section of this Note.

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

		Millions of Dollars		
		2020	2019	20
Exploratory well costs capitalized for a period of one year or less	$	**156**	206	14
Exploratory well costs capitalized for a period greater than one year		**526**	814	71
Ending balance	$	**682**	1,020 *	85
Number of projects with exploratory well costs capitalized for a period greater than one year		**22**	23	2

**Includes $313 million of assets held for sale in Australia at December 31, 2019.*

The following table provides a further aging of those exploratory well costs that have been capitalized for mo
than one year since the completion of drilling as of December 31, 2020:

		Millions of Dollars			
			Suspended Since		
		Total	2017–2019	2014–2016	2004–20
NPRA—Alaska(1)		240	190	50	
Surmont—Canada(1)		120	4	31	8
Narwhal Trend—Alaska(1)		52	52	-	
PL782S—Norway(1)		22	22	-	
WL4-00—Malaysia(1)		17	17	-	
NC 98—Libya(2)		13	-	9	
Other of $10 million or less each(1)(2)		62	26	19	1
Total	$	526	311	109	10

(1)Additional appraisal wells planned.
(2)Appraisal drilling complete; costs being incurred to assess development.

Exploration Expenses
The charges discussed below are included in the "Exploration expenses" line on our consolidated income statement.

_2020_
In our Alaska segment, we recorded a before-tax impairment of $828 million for the entire associated carryi
value of capitalized undeveloped leasehold costs related to our Alaska North Slope Gas asset. 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 proje
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 o
the project due to changes in the economic environment; however, AGDC decided to continue on its own, focusing primarily on permitting efforts. Currently, AGDC is in the process of seeking new sponsors for the project. Given current market conditions, we no longer believe the project will advance and, there is no current market for the asset.

In our Other International segment, our interests in the Middle Magdalena Basin of Colombia are in force majeure. We have no immediate plans to perform under existing contracts; therefore, in 2020, we recorded a
before-tax expense totaling $84 million for dry hole costs of a previously suspended well and an impairment
the associated capitalized undeveloped leasehold carrying value.

In our Asia Pacific segment, we recorded before-tax expense of $50 million related to dry hole costs of a previously suspended well and an impairment of the associated capitalized undeveloped leasehold carrying value associated with the Kamunsu East Field in Malaysia that is no longer in our development plans.

_2019_
In our Lower 48 segment, we recorded a before-tax impairment of $141 million for the associated carrying value of capitalized undeveloped leasehold costs and dry hole expenses of $111 million before-tax due to ou
decision to discontinue exploration activities related to our Central Louisiana Austin Chalk acreage.

Note 8—Impairments

During 2020, 2019 and 2018, we recognized the following before-tax impairment charges:

		Millions of Dollars		
		2020	2019	20
Alaska	$	**-**	-	2
Lower 48		**804**	402	6
Canada		**3**	2	
Europe, Middle East and North Africa		**6**	1	(7
Asia		**-**	-	1
Pacific	$	**813**	405	2

<u>2020</u>

During 2020, we recorded impairments of $813 million, primarily related to certain non-core assets in the Lower 48. Due to a significant decrease in the outlook for current and long-term natural gas prices in early 2020, we recorded impairments of $523 million, primarily for the Wind River Basin operations area, consisting of developed properties in the Madden Field and the Lost Cabin Gas Plant, in the first quarter of 2020. Additionally, due primarily to changes in development plans solidified in the last quarter of 2020, we recognized additional impairments of $287 million in the Lower 48 during the fourth quarter. See Note 14—Fair Value Measurement, for additional information.

<u>2019</u>

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 4—Asset Acquisitions and Dispositions, for additional information on this disposition.

<u>2018</u>

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, Middle East 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 ceased production and were impaired prior years, partly offset by an increased ARO estimate on a field in Norway which ceased production.

Note 9—Asset Retirement Obligations and Accrued Environmental Costs

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

		Millions of Dollars	
		2020	20
Asset retirement obligations	**$**	**5,573**	6,20
Accrued environmental costs		**180**	17
Total asset retirement obligations and accrued environmental costs		**5,753**	6,37
Asset retirement obligations and accrued environmental costs due within one year*		**(323)**	(1,02
Long-term asset retirement obligations and accrued environmental costs	**$**	**5,430**	5,35

**Classified as a current liability on the balance sheet under "Other accruals." For 2019, $741 million relates to assets which were held for sa as of December 31, 2019, and subsequently sold in 2020. For additional information see Note 4—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 retiremen 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 tak 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 2020 and 2019, our overall ARO changed as follows:

		Millions of Dollars	
		2020	20
Balance at January 1	**$**	**6,206**	7,90
Accretion of discount		**248**	32
New obligations		**262**	15
Changes in estimates of existing obligations		**(307)**	5
Spending on existing obligations		**(116)**	(22
Property dispositions		**(771)**	(1,92
Foreign currency translation		**51**	(8
Balance at December 31	**$**	**5,573**	6,20

Accrued Environmental Costs

Total accrued environmental costs at December 31, 2020 and 2019, were $180 million and $171 million, respectively.

We had accrued environmental costs of $116 million and $112 million at December 31, 2020 and 2019, respectively, related to remediation activities in the U.S. and Canada. We had also accrued in Corporate and Other $48 million and $47 million of environmental costs associated with sites no longer in operation at December 31, 2020 and 2019, respectively. In addition, $16 million and $12 million were included at both December 31, 2020 and 2019, respectively, where the company has been named a potentially responsible pa 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 discount using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmen liabilities of $106 million at December 31, 2020. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $23 million in 2021, $17 million i 2022, $18 million in 2023, $3 million in 2024, $2 million in 2025, and $103 million for all future years after 2025.

Note 10—Debt

Long-term debt at December 31 was:

		Millions of Dollars	
		2020	20
9.125% Debentures due 2021	$	**123**	12
2.4% Notes due 2022		**329**	32
7.65% Debentures due 2023		**78**	7
3.35% Notes due 2024		**426**	42
8.2% Debentures due 2025		**134**	13
3.35% Notes due 2025		**199**	19
6.875% Debentures due 2026		**67**	6
4.95% Notes due 2026		**1,250**	1,25
7.8% Debentures due 2027		**203**	20
7.375% Debentures due 2029		**92**	9
7% Debentures due 2029		**200**	20
6.95% Notes due 2029		**1,549**	1,54
8.125% Notes due 2030		**390**	39
7.2% Notes due 2031		**575**	57
7.25% Notes due 2031		**500**	50
7.4% Notes due 2031		**500**	50
5.9% Notes due 2032		**505**	50
4.15% Notes due 2034		**246**	24
5.95% Notes due 2036		**500**	50
5.951% Notes due 2037		**645**	64
5.9% Notes due 2038		**600**	60
6.5% Notes due 2039		**2,750**	2,75
4.3% Notes due 2044		**750**	75
5.95% Notes due 2046		**500**	50
7.9% Debentures due 2047		**60**	6
Floating rate notes due 2022 at 1.12% – 2.81% during 2020 and 2.81% – 3.58% during 2019		**500**	50
Marine Terminal Revenue Refunding Bonds due 2031 at 0.1% – 7.5% during 2020 and 1.08% – 2.45% during 2019		**265**	26
Industrial Development Bonds due 2035 at 0.11% – 7.5% during 2020 and 1.08% – 2.45% during 2019		**18**	1
Commercial Paper at 0.08% – 0.23% during 2020		**300**	
Other		**38**	1
Debt at face value		**14,292**	13,97
Finance leases		**891**	72
Net unamortized premiums, discounts and debt issuance costs		**186**	20
Total		**15,369**	14,89
Short-term debt		**(619)**	(10
Long-term debt	$	**14,750**	14,79

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2021 through 2025 are: $619 million, $1,001 million, $259 million, $579 million and $465 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. The amount of the facility is not subject to redetermination prior to its expiration date.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in th 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 our ability to issue up to $6.0 billion of commercial paper, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. We issued $300 million of commercial paper in the third quarter of 2020, which is included in the short-term debt on our consolidated balance sheet. With $300 million of commercial paper outstanding and no direct borrowings or letters of credit, we had access to $5.7 billion in available borrowing capacity under our revolving credit facility at December 31, 2020. We had no direct borrowings, letters of credit, nor outstanding commercial paper as of December 31, 2019.

At both December 31, 2020 and 2019, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. If they are ever redeemed, we have the ability and intent to refinance on a long-term basis, therefore, the VRDBs are included in the "Long-term debt" line on our consolidated balance sheet.

For information on Finance Leases, see Note 16—Non-Mineral Leases.

On January 15, 2021, we completed the acquisition of Concho in an all-stock transaction. In the acquisition, we assumed Concho's publicly traded debt, which was recorded at fair value of $4.7 billion on the acquisitio date. On December 7, 2020, we launched a debt exchange offer which settled on February 8, 2021. Of the approximately $3.9 billion in aggregate principal amount of Concho's notes subject to the exchange offer, 98 percent, or approximately $3.8 billion, was tendered and exchanged for new debt issued by ConocoPhillips. The new debt received in the exchange is fully and unconditionally guaranteed by ConocoPhillips Company. In conjunction with the exchange offer, Concho successfully solicited consents to amend each of the indentures governing the Concho notes to eliminate certain covenants, restrictive provisions, events of defau and the requirements for certain Concho subsidiaries to make future guarantees. For additional information on the acquisition see Note 25—Acquisition of Concho Resources Inc.

Note 11—Guarantees

At December 31, 2020, 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 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 expec future performance to be either immaterial or have only a remote chance of occurrence.

APLNG

Guarantees

At December 31, 2020, we had outstanding multiple guarantees in connection with our 37.5 percent ownersh interest in APLNG. The following is a description of the guarantees with values calculated utilizing Decemb 2020 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 to be 10 years. Our maximum exposure under this guarantee is approximately $170 millio and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2020, 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 liabilit arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sal agreements with remaining terms of 1 to 21 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $770 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. Futu 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 16 to 25 years or the life of the venture. Our maximum potential amount of future payments related to the guarantees is approximately $130 million and would become payable if APLNG does not perform. December 31, 2020, the carrying value of these guarantees was approximately $7 million.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $730 million, which consist primarily of guarantees of the residual value of leased office buildings, guarante of the residual value of corporate aircraft, and a guarantee for our portion of a joint venture's project finance reserve accounts. These guarantees have remaining terms of one to six years and would become payable if certain asset values are lower than guaranteed amounts at the end of the lease or contract term, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties. At December 31, 2020, the carrying value of these guarantees was approximately $11 million.

Indemnifications

Over the years, we have entered into agreements to sell ownership interests in certain legal entities, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes and environmental liabilities. Most of these indemnifications are related to tax issues and the majority of these expire in 2021. Those related to environmental issues have terms that are generally indefin and the maximum amounts of future payments are generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2020, was approximately $50 million. We amortize the indemnification liability over the relevant time period the indemnity is in effect, 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 natur of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. For additional information about environmental liabilities, see Note 12—Contingencies an Commitments.

Note 12—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 activ and inactive sites. We regularly assess the need for accounting recognition or disclosure of those 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 low end of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveri We accrue receivables for insurance or other third-party recoveries when applicable. 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 18—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 continger liability exposures will exceed current accruals by an amount that would have a material adverse impact on c 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 futu 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 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 accoun stakeholder and business considerations. When measuring environmental liabilities, we also consider our pr 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 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 potential 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 proportiona 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 an 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 9—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Litigation and Other Contingencies

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royal 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 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 th adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

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 suc company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2020, we had performance obligations secured by letters of credit of $249 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 mandate 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. I response to this expropriation, ConocoPhillips initiated international arbitration on November 2, 2007, with t 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 th 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 h 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 before ICSID, and annulment proceedings are underway.

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. 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 notic of default to PDVSA on October 14 and November 12, 2019, and to date PDVSA has failed to cure its breach As a result, ConocoPhillips has resumed legal enforcement actions. ConocoPhillips has ensured that the settlement and any actions taken in enforcement 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 $33 million plus interest under the Corocoro contracts. ConocoPhillips is seeking recognition and enforcement of the award in various jurisdictions. ConocoPhillip 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.

The Office of Natural Resources Revenue (ONRR) has conducted audits of ConocoPhillips' payment of royalties on federal lands and has issued multiple orders to pay additional royalties to the federal governmen ConocoPhillips has appealed these orders and strongly objects to the ONRR claims. The appeals are pending with the Interior Board of Land Appeals (IBLA), except for one order that is the subject of a lawsuit ConocoPhillips filed in 2016 in New Mexico federal court after its appeal was denied by the IBLA.

Beginning in 2017, governmental and other entities in several states in the U.S. have filed lawsuits against oi and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. Additional lawsuits with similar allegations are expected to be filed. The amounts claimed by plaintiffs are unspecified and the legal and factual issues involved in these cases are unprecedented. ConocoPhillips believes these lawsuits are factually and legally meritless and are an inappropriate vehicle to address the challenges associated with climate change and will vigorously defend against such lawsuits.

Several Louisiana parishes and the State of Louisiana have filed 43 lawsuits under Louisiana's State and Loc Coastal Resources Management Act (SLCRMA) against oil and gas companies, including ConocoPhillips, seeking compensatory damages for contamination and erosion of the Louisiana coastline allegedly caused by historical oil and gas operations. ConocoPhillips entities are defendants in 22 of the lawsuits and will vigorously defend against them. Because Plaintiffs' SLCRMA theories are unprecedented, there is uncertain about these claims (both as to scope and damages) and any potential financial impact on the company.

In 2016, ConocoPhillips, through its subsidiary, The Louisiana Land and Exploration Company LLC, submitted claims as the largest private wetlands owner in Louisiana within the settlement claims administration process related to the oil spill in the Gulf of Mexico in April 2010. In July 2020, the claims administrator issued an award to the company which, after fees and expenses, totaled approximately $90 million, and was received in the third quarter of 2020.

In October 2020, the Bureau of Safety and Environmental Enforcement (BSEE) ordered the prior owners of Outer Continental Shelf (OCS) Lease P-0166, including ConocoPhillips, to decommission the lease facilities including two offshore platforms located near Carpinteria, California. This order was sent after the current owner of OCS Lease P-0166 relinquished the lease and abandoned the lease platforms and facilities. Phillips Petroleum Company, a legacy company of ConocoPhillips, held a 25 percent interest in this lease and operat these facilities, but sold its interest approximately 30 years ago. ConocoPhillips has not had any connection the operation or production on this lease since that time. ConocoPhillips is challenging this order.

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 the company's business. The aggregate amounts of estimated payments under these various agreements are: 2021—$7 million; 2022—$7 million; 2023—$7 million; 2024—$7 million; 2025—$7 million; and 2026 and after—$51 million. Total payments under the agreements were $25 million in 2020, $25 million in 2019 and $39 million in 2018.

Note 13—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs, capture market opportunities, and manage foreign exchange currency risk.

Commodity Derivative Instruments
Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and NGLs.

Commodity 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 physi 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 apply 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	
		2020	20
Assets			
Prepaid expenses and other current assets	$	**229**	28
Other assets		**26**	3
Liabilities			
Other accruals		**202**	28
Other liabilities and deferred credits		**18**	2

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

		Millions of Dollars		
		2020	2019	20
Sales and other operating revenues	$	**19**	141	4
Other income (loss)		**4**	4	
Purchased commodities		**11**	(118)	(4

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

	Open Position Long/(Short)	
	2020	20
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(20)**	(
Basis	**(10)**	(2

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 cas returns from net investments in foreign affiliates, and investments in equity securities.

Our foreign currency exchange derivative instruments are held at fair value on our consolidated balance shee Related cash flows are recorded as operating activities on our consolidated statement of cash flows. We do not apply hedge accounting to 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	
		2020	201
Assets			
Prepaid expenses and other current assets	**$**	**2**	
Liabilities			
Other accruals		**16**	2(
Other liabilities and deferred credits		**-**	8

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

		Millions of Dollars		
		2020	2019	20
Foreign currency transaction (gains) losses	**$**	**(40)**	16	

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

		In Millions Notional Currency	
		2020	20
Foreign Currency Exchange Derivatives			
Buy British pound, sell euro	GBP	**-**	
Sell British pound, buy euro	GBP	**5**	
Sell Canadian dollar, buy U.S. dollar	CAD	**370**	1,33

At December 31, 2020, we had outstanding foreign currency exchange forward contracts to sell $0.45 billion CAD at $0.748 CAD against the U.S. dollar. 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.

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 for a predetermined amou of time.
- Demand deposits: Interest bearing deposits placed with financial institutions. Deposited funds can 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. government agencies.
- Foreign government obligations: Securities issued by foreign governments.
- 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 and the table reflects remaining maturities at December 31, 2020 and 2019:

	Millions of Dollars				
	Carrying Amount				
	Cash and Cash Equivalents		Short-Term Investments		Investments and L Term Receivables
	2020	2019	**2020**	2019	**2020**
Cash	$ **597**	759			
Demand Deposits	**1,133**	1,483			
Time Deposits					
1 to 90 days	**1,225**	2,030	**2,859**	1,395	
91 to 180 days			**448**	465	
Within one year			**13**	-	
One year through five years					**1**
Commercial Paper					
1 to 90 days	**-**	413	**-**	1,069	
U.S. Government Obligations					
1 to 90 days	**23**	394	**-**	-	
	$ **2,978**	5,079	**3,320**	2,929	**1**

The following investments in debt securities classified as available for sale are carried on our consolidated balance sheet at fair value as of December 31, 2020 and 2019:

	Millions of Dollars					
	Carrying Amount					
	Cash and Cash Equivalents		Short-Term Investments		Investments and L… Term Receivables	
	2020	2019	**2020**	2019	**2020**	
Major Security Type						
Corporate Bonds	$ **-**	1	**130**	59	**143**	
Commercial Paper	**13**	8	**155**	30		
U.S. Government Obligations	**-**	-	**4**	10	**13**	
U.S. Government Agency Obligations					**17**	
Foreign Government Obligations					**2**	
Asset-backed Securities			**-**	-	**41**	
	$ **13**	9	**289**	99	**216**	

Cash and Cash Equivalents and Short-Term Investments have remaining maturities within one year. Investments and Long-Term Receivables have remaining maturities greater than one year through five years.

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

	Millions of Dollars			
	Amortized Cost Basis		Fair Value	
	2020	2019	**2020**	20…
Major Security Type				
Corporate bonds	$ **271**	159	**273**	15…
Commercial paper	**168**	38	**168**	3…
U.S. government obligations	**17**	25	**17**	2…
U.S. government agency obligations	**17**	-	**17**	
Foreign government obligations	**2**	-	**2**	
Asset-backed securities	**41**	19	**41**	1…
	$ **516**	241	**518**	24…

As of December 31, 2020 and December 31, 2019, total unrealized losses for debt securities classified as available for sale with net losses were negligible. Additionally, as of December 31, 2020 and December 2019, investments in these debt securities in an unrealized loss position for which an allowance for credit losses has not been recorded were negligible.

For the year ended December 31, 2020, proceeds from sales and redemptions of investments in debt securiti… classified as available for sale were $422 million. Gross realized gains and losses included in earnings from those sales and redemptions were negligible. The cost of securities sold and redeemed is determined using t… specific identification method.

Credit Risk
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalen 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 a financial institutions, and high-quality corporate bonds. Our long-term investments in debt securities are placed in high-quality corporate bonds, U.S. government and government agency obligations, foreign 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 receivab 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. At our option, we may require collateral to limit the exposure to loss including, letters of credit, prepayments and surety bonds, as well as master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owe 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 rever 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 w in a liability position on December 31, 2020 and December 31, 2019, was $25 million and $79 million, respectively. For these instruments, no collateral was posted as of December 31, 2020 or December 31, 201 If our credit rating had been downgraded below investment grade on December 31, 2020, we would have be required to post $23 million of additional collateral, either with cash or letters of credit.

Note 14—Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at the reporting date using an e 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. Th 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. There were no material transfers into or out of Level 3 duri
2020 or 2019.

Recurring Fair Value Measurement
Financial assets and liabilities reported at fair value on a recurring basis primarily include our investment in Cenovus Energy common 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 ar sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing servi 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, asset-backed securities, U.S. government agency obligations and foreign government obligations 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 historic relationships among various commodities, modeled market prices, time value, volatility factors and othe 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 recurrir basis):

	Millions of Dollars							
	December 31, 2020				December 31, 2019			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	To
Assets								
Investment in Cenovus Energy	$ **1,256**	**-**	**-**	**1,256**	2,111	-	-	2,11
Investments in debt securities	**17**	**501**	**-**	**518**	25	216	-	24
Commodity derivatives	**142**	**101**	**12**	**255**	172	114	36	32
Total assets	$ **1,415**	**602**	**12**	**2,029**	2,308	330	36	2,67
Liabilities								
Commodity derivatives	$ **120**	**91**	**9**	**220**	174	115	22	31
Total liabilities	$ **120**	**91**	**9**	**220**	174	115	22	31

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	Ne Amount
December 31, 2020								
Assets	**$**	**255**	**2**	**253**	**157**	**96**	**10**	**86**
Liabilities		**220**	**1**	**219**	**157**	**62**	**4**	**58**
December 31, 2019								
Assets	$	322	3	319	193	126	4	122
Liabilities		311	4	307	193	114	12	102

At December 31, 2020 and December 31, 2019, 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-T Lo
Year ended December 31, 2020						
Net PP&E (held for use)						
March 31, 2020	**$**	**65**	**-**	**-**	**65**	**52**
December 31, 2020		**268**	**-**	**-**	**268**	**28**
Year ended December 31, 2019						
Net PP&E (held for sale)						
November 30, 2019	$	194	194	-	-	35
December 31, 2019		166	166	-	-	2
Equity Method Investments						
March 31, 2019		171	171	-	-	6
May 31, 2019		30	-	30	-	9

Net PP&E (held for use)

During 2020, the estimated fair value of certain non-core assets included in our Lower 48 segment declined t amounts below the carrying values. The carrying values were written down to fair value. The fair values were estimated based on internal discounted cash flow models using the following estimated assumptions: estimat future production, an outlook of future prices from a combination of exchanges (short-term) coupled with pricing service companies and our internal outlook (long-term), future operating costs and capital expenditur and a discount rate believed to be consistent with those used by principal market participants. The range and arithmetic average of significant unobservable inputs used in the Level 3 fair value measurements for significant assets were as follows:

	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Inputs	Ra (Arithmetic Avera
March 31, 2020				
Wind River Basin	$ 65	Discounted cash flow	Natural gas production (MMCFD)	8.4 - 55.2 (22
			Natural gas price outlook* ($/MMBTU)	$2.67 - $9.17 ($5.
			Discount rate**	7.9% - 9.1% (8.3

**Henry Hub natural gas price outlook based on a combination of external pricing service companies' outlooks for years 2022-2034; future prices escalated at 2. annually after year 2034.*
***Determined as the weighted average cost of capital of a group of peer companies, adjusted for risks where appropriate.*

	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Inputs	Ra (Arithmetic Avera
December 31, 2020				
Central Basin Platform	$ 244	Discounted cash flow	Commodity production (MBOED)	0.5 - 12.7 (3
			Commodity price outlook* ($/BOE)	$37.35 - $115 ($73.
			Discount rate**	6.8% - 7.7% (7.4

**Commodity price outlook based on a combination of external pricing service companies' and our internal outlook for years 2023-2050; future prices escalated at 2.0% annually after year 2050.*
***Determined as the weighted average cost of capital of a group of peer companies, adjusted for risks where appropriate.*

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 the assets were determined by their negotiated selling prices (Level 1). For additional information see Note 4—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. Investments using Level 1 inputs were written down to fair value, less costs to sell, determined b negotiated selling prices. For additional information, see Note 4—Asset Acquisitions and Dispositions and Note 5—Investments, Loans and Long-Term Receivables. An investment using Level 2 inputs was determined to have a fair value below its carrying value, and was written down to fair value.

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 Loan and advances—related parties.

- Investment in Cenovus Energy: See Note 6—Investment in Cenovus Energy for a discussion of the carrying value and fair value of our investment in Cenovus Energy common 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 13—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 5—Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of account 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 Lev 2 in the fair value hierarchy.
- Commercial paper: The carrying amount of our commercial paper instruments approximates fair val and is reported on the balance sheet as short-term debt. See Note 10—Debt, for additional information.

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	
	2020	2019	**2020**	20
Financial assets				
Investment in Cenovus Energy	$ **1,256**	2,111	**1,256**	2,11
Commodity derivatives	**88**	125	**88**	12
Investments in debt securities	**518**	241	**518**	24
Loans and advances—related parties	**220**	339	**220**	33
Financial liabilities				
Total debt, excluding finance leases	**14,478**	14,175	**19,106**	18,10
Commodity derivatives	**59**	106	**59**	10

Commodity Derivatives

At December 31, 2020, commodity derivative assets and liabilities are presented net with $10 million in obligations to return cash collateral and $4 million of rights to reclaim cash collateral, respectively. 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.

Note 15—Equity

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

	Shares		
	2020	2019	20
Issued			
Beginning of year	**1,795,652,203**	1,791,637,434	1,785,419,17
Distributed under benefit plans	**3,192,064**	4,014,769	6,218,25
End of year	**1,798,844,267**	1,795,652,203	1,791,637,43
Held in Treasury			
Beginning of year	**710,783,814**	653,288,213	608,312,03
Repurchase of common stock	**20,018,275**	57,495,601	44,976,17
End of year	**730,802,089**	710,783,814	653,288,21

Preferred Stock
We have authorized 500 million shares of preferred stock, par value $0.01 per share, none of which was issu or outstanding at December 31, 2020 or 2019.

Noncontrolling Interests
In the second quarter of 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations. These assets included the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures in which there was a noncontrolling interest. As a result, as of December 31, 2020, we had no noncontrolling interests. At December 31, 2019, we had $69 million of equity outstanding in the same joint ventures.

Repurchase of Common Stock
In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. Cost of share repurchases were $892 million, $3,500 million, $2,999 million in 2020, 2019 and 2018, respectively. Share repurchases were suspended in the seco and third quarters of 2020 in response to the economic downturn. In the fourth quarter of 2020, we resumed share repurchases, repurchasing $0.2 billion of shares in October, until suspending further repurchases upon entry into a definitive agreement to acquire Concho. In February 2021, we resumed share repurchases following our Concho acquisition. Share repurchases since inception of our current program totaled 189 million shares at a cost of $10,517 million, as of December 31, 2020.

Note 16—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 tha 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. F additional information about guarantees, see Note 11—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 or contains a lease at contract inception. We adopted the provisions of FASB ASU No. 2016-02, "Leases"

(ASC Topic 842) and its amendments, beginning January 1, 2019. This ASU superseded the requirements in FASB ASC Topic 840 "Leases" (ASC Topic 840). 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 no 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 t 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 o 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, terminatio 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 su options. We use our incremental borrowing rate as the discount rate in determining the present value of futu 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 asset 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, w 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 activitie 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 cou 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 proportio basis consistent with its ownership interest in the investee company. In addition, the company has historical recorded finance lease assets and liabilities associated with certain oil and gas joint ventures on a proportiona basis pursuant to accounting guidance applicable prior to January 1, 2019. 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 subj to reconsideration upon the modification or other required reassessment of the arrangements prior to lease te expiration.

The following table summarizes the right-of-use assets and lease liabilities for both the operating and finance leases on our consolidated balance sheet as of December 31:

	Millions of Dollars				
		2020		2019	
		Operating Leases	Finance Leases	Operating Leases	Finance Leases
Right-of-Use Assets					
Properties, plants and equipment					
Gross	$		**1,375**		1,03
Accumulated DD&A			**(721)**		(64
Net PP&E*			**654**		39
Prepaid expenses and other current assets	$	**-**		40	
Other assets		**783**		896	
Lease Liabilities					
Short-term debt**	$		**168**		8
Other accruals		**226**		347	
Long-term debt***			**723**		63
Other liabilities and deferred credits		**559**		585	
Total lease liabilities	$	**785**	**891**	932	7

* *Includes proportionately consolidated finance lease assets of $258 million at December 31, 2020 and $335 million at December 31, 2019*

** *Includes proportionately consolidated finance lease liabilities of $97 million at December 31, 2020 and $56 million at December 31, 2019*

*** *Includes proportionately consolidated finance lease liabilities of $522 million at December 31, 2020 and $579 million at December 31, 2019.*

The following table summarizes our lease costs for 2020 and 2019:

	Millions of Dollars		
		2020	20
Lease Cost*			
Operating lease cost	$	**321**	3
Finance lease cost			
Amortization of right-of-use assets		**163**	
Interest on lease liabilities		**34**	
Short-term lease cost**		**42**	
Total lease cost***	$	**560**	5

* *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.*

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

The following table summarizes the lease terms and discount rates as of December 31:

	2020	20
Lease Term and Discount Rate		
Weighted-average term (years)		
Operating leases	**6.11**	5.
Finance leases	**7.12**	8.
Weighted-average discount rate (percent)		
Operating leases	**2.78**	3.
Finance leases	**4.27**	5.

The following table summarizes other lease information for 2020 and 2019:

		Millions of Dollars	
		2020	20
Other Information*			
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$	**232**	2
Operating cash flows from finance leases		**11**	
Financing cash flows from finance leases		**255**	
Right-of-use assets obtained in exchange for operating lease liabilities	$	**250**	4
Right-of-use assets obtained in exchange for finance lease liabilities		**426**	

**The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers. I addition, pursuant to other applicable accounting guidance, lease payments made in connection with preparing another asset for its intended u 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, 2020

		Millions of Dollars	
		Operating Leases	Finan Leas
Maturity of Lease Liabilities			
2021	$	245	21
2022		155	16
2023		116	14
2024		94	11
2025		55	8
Remaining years		200	32
Total*		865	1,04
Less: portion representing imputed interest		(80)	(15
Total lease liabilities	$	785	89

**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.*

For the year ended December 31, 2018 operating lease rental expense pursuant to ASC Topic 840 was:

		Millions of Dollars
Total rentals	$	2
Less: sublease rentals		(1
	$	23

Note 17—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	
		2020		2019		**2020**	20
		U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation							
Benefit obligation at January 1	$	**2,319**	**3,880**	2,136	3,438	**216**	21
Service cost		**85**	**54**	79	69	**2**	
Interest cost		**66**	**85**	79	97	**6**	
Plan participant contributions		**-**	**1**	-	2	**18**	2
Plan amendments		**-**	**2**	-	-	**(30)**	
Actuarial loss		**319**	**398**	278	387	**7**	2
Benefits paid		**(241)**	**(151)**	(253)	(147)	**(49)**	(5
Curtailment		**-**	**2**	-	(69)	**-**	
Recognition of termination benefits		**-**	**3**	-	1	**-**	
Foreign currency exchange rate change		**-**	**129**	-	102	**-**	
Benefit obligation at December 31*	$	**2,548**	**4,403**	2,319	3,880	**170**	21
**Accumulated benefit obligation portion of above at December 31:*	*$*	***2,359***	***4,095***	*2,161*	*3,594*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	$	**1,591**	**4,306**	1,336	3,358	**-**	
Actual return on plan assets		**321**	**416**	273	529	**-**	
Company contributions		**99**	**60**	235	464	**31**	3
Plan participant contributions		**-**	**1**	-	2	**18**	2
Benefits paid		**(241)**	**(151)**	(253)	(147)	**(49)**	(5
Foreign currency exchange rate change		**-**	**161**	-	100	**-**	
Fair value of plan assets at December 31	$	**1,770**	**4,793**	1,591	4,306	**-**	
Funded Status	$	**(778)**	**390**	(728)	426	**(170)**	(21

		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2020		2019		**2020**	20
		U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31							
Noncurrent assets	$	**-**	**746**	-	765	**-**	
Current liabilities		**(56)**	**(11)**	(21)	(6)	**(39)**	(4
Noncurrent liabilities		**(722)**	**(345)**	(707)	(333)	**(131)**	(17
Total recognized	$	**(778)**	**390**	(728)	426	**(170)**	(21

Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**2.30** %	**1.80**	3.25	2.35	**2.15**	3.1
Rate of compensation increase	**4.00**	**3.10**	4.00	3.35		
Interest crediting rate for applicable benefits	**2.10**	**-**	4.10	-		

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**3.05** %	**2.35**	3.95	2.90	**3.10**	4.0
Expected return on plan assets	**5.80**	**3.60**	5.80	4.10		
Rate of compensation increase	**4.00**	**3.35**	4.00	3.65		
Interest crediting rate for applicable benefits	**4.10**	**-**	4.35	-		

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 eac class of assets.

The following tables set forth information related to the Company's pension plans with projected and accumulated benefit obligations in excess of the fair value of the plans' assets as of December 31, 2020 and 2019:

	Millions of Dollars			
	Pension Benefits			
	2020		2019	
	U.S.	**Int'l.**	U.S.	Int
Pension Plans with Projected Benefit Obligation in Excess of Plan Assets				
Projected benefit obligation	$ **2,548**	**391**	2,319	35
Fair value of plan assets	**1,770**	**35**	1,591	4
Pension Plans with Accumulated Benefit Obligation in Excess of Plan Assets				
Accumulated benefit obligation	$ **2,359**	**338**	2,161	29
Fair value of plan assets	**1,770**	**35**	1,591	4

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:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2020		2019		**2020**	20
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial loss	$ **467**	**326**	479	227	**14**	
Unrecognized prior service credit	**-**	**-**	-	(2)	**(182)**	(18

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2020		2019		**2020**	20
	U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)						
Net gain (loss) arising during the period	$ **(83)**	**(120)**	(79)	51	**(7)**	(2
Amortization of actuarial (gain) loss included in income (loss)*	**95**	**21**	116	32	**1**	(
Net change during the period	$ **12**	**(99)**	37	83	**(6)**	(2
Prior service credit (cost) arising during the period	$ **-**	**(1)**	-	-	**30**	
Amortization of prior service cost (credit) included in income (loss)	**-**	**(1)**	-	(2)	**(31)**	(3
Net change during the period	$ **-**	**(2)**	-	(2)	**(1)**	(3

**Includes settlement (gains) losses recognized in 2020 and 2019.*

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		
		2020		2019		2018		**2020**	2019	20
		U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost										
Service cost	$	**85**	**54**	79	69	83	81	**2**	1	
Interest cost		**66**	**85**	79	97	99	107	**6**	8	
Expected return on plan assets		**(85)**	**(145)**	(74)	(138)	(114)	(155)	**-**	-	
Amortization of prior service credit		**-**	**(1)**	-	(2)	-	(5)	**(31)**	(33)	(3
Recognized net actuarial loss (gain)		**51**	**22**	54	32	53	31	**1**	(2)	(
Settlements loss (gain)		**44**	**(1)**	62	-	196	-	**-**	-	
Net periodic benefit cost	**$**	**161**	**14**	200	58	317	59	**(22)**	(26)	(2

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

We recognized pension settlement losses of $43 million in 2020, $62 million in 2019, and $196 million in 2018 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

During 2020 and 2019, the actuarial losses related to the benefit obligation for U.S. and international plans were primarily related to a decrease in the discount rates.

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 i 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, 201 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 straig 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 2021 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 202 that increases to 5 percent by 2028.

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 the investment program from time to time. The target allocations for plan assets are 28 percent equity securities, 68 percent debt securities, 3 percent real estate and 1 percent other. Generally, the plan investmen 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, 2020 and 2019.

- 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 deb securities categorized in Level 2 are estimated using recently executed transactions and quoted mark 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., observabl 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 o 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 owe 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 marke prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2020, the participating interest in the annuity contract was valued at $94 million and consisted of $233 million in debt securities, less $139 million for the accumulated benefit obligation covered by the contract. 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 $14 million for the accumulated benefit obligation covered by the contract. 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	To
2020									
Equity securities									
U.S.	$	**-**	**3**	**5**	**8**	**-**	**-**	**-**	
International		**99**	**-**	**-**	**99**	**-**	**-**	**-**	
Mutual funds		**72**	**-**	**-**	**72**	**235**	**734**	**-**	**96**
Debt securities									
Corporate		**-**	**1**	**-**	**1**	**-**	**-**	**-**	
Mutual funds		**-**	**-**	**-**	**-**	**455**	**-**	**-**	**45**
Cash and cash equivalents		**-**	**-**	**-**	**-**	**74**	**-**	**-**	**7**
Derivatives		**-**	**-**	**-**	**-**	**6**	**-**	**-**	
Real estate		**-**	**-**	**-**	**-**	**-**	**-**	**142**	**14**
Total in fair value hierarchy	$	**171**	**4**	**5**	**180**	**770**	**734**	**142**	**1,64**
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$				**678**				**2,96**
Debt securities									
Common/collective trusts					**730**				**6**
Cash and cash equivalents					**8**				
Real estate					**79**				**11**
Total**	$	**171**	**4**	**5**	**1,675**	**770**	**734**	**142**	**4,78**

**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 $94 million and net receivables related to security transactions of $7 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	To
2019									
Equity securities									
U.S.	$	94	-	7	101	435	-	-	43
International		98	-	-	98	266	-	-	26
Mutual funds		93	-	-	93	245	267	-	51
Debt securities									
Government		-	-	-	-	1,412	-	-	1,41
Corporate		-	2	-	2	-	-	-	
Mutual funds		-	-	-	-	392	-	-	39
Cash and cash equivalents		-	-	-	-	98	-	-	9
Derivatives		-	-	-	-	11	-	-	1
Real estate		-	-	-	-	-	-	132	13
Total in fair value hierarchy	$	285	2	7	294	2,859	267	132	3,2
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$				457				16
Debt securities									
Common/collective trusts					637				70
Cash and cash equivalents					25				
Real estate					83				11
Total**	$	285	2	7	1,496	2,859	267	132	4,29

**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.*

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 Retiremen 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 2021, we expect to contribute approximately $2 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $75 million 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 contra and which reflect expected future service, as appropriate, are expected to be paid:

		Millions of Dollars		
		Pension Benefits		Other Benefit
		U.S.	Int'l.	
2021	$	532	147	2
2022		289	151	2
2023		248	156	1
2024		232	162	1
2025		215	166	1
2026–2030		845	897	5

Severance Accrual
The following table summarizes our severance accrual activity for 2020, 2019 and 2018:

		Millions of Dollars		
		2020	2019	20
Balance at January 1	$	**23**	48	5
Accruals		**14**	(1)	7
Benefit payments		**(13)**	(24)	(7
Foreign currency translation adjustments		**-**	-	(
Balance at December 31	**$**	**24**	23	4

Of the remaining balance at December 31, 2020, $8 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 elect to opt out of Title II are eligible to receive a Company Retirement Contribution (CRC) of 6 percent of eligib pay into their CPSP. After three years of service with the company, the employee is 100 percent vested in an CRC. Company contributions charged to expense for the CPSP and predecessor plans were $62 million in 2020, $82 million in 2019, and $82 million in 2018.

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 $25 million in 2020, $30 million in 2019, and $31 million in 2018.

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 ou 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 comm 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 continu 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 th 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 tim

We recognize expense on a straight-line basis over the service period for the entire award, whether the awarc was granted with ratable or cliff vesting.

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

		Millions of Dollars		
		2020	2019	20
Compensation cost	$	**159**	274	26
Tax benefit		**40**	71	6

Stock Options—Stock options granted under the provisions of the Plan and prior plans permit purchase of c common stock at exercise prices equivalent to the average fair market value of ConocoPhillips common stoc 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 c grant. Options awarded to certain employees already eligible for retirement vest within six months of the gra 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 for 2018 and 2019 awards and stock-settled for 2020 awards.

The following summarizes our stock option activity for the year ended December 31, 2020:

				Millions of Doll
	Options		Weighted-Average Exercise Price	Aggreg Intrinsic Va
Outstanding at December 31, 2019	18,040,197	$	54.11	$ 2
Exercised	**(1,111,805)**		**38.80**	
Forfeited	**(5,867)**		**49.76**	
Expired or cancelled	-			
Outstanding at December 31, 2020	**16,922,525**	**$**	**55.12**	**$**
Vested at December 31, 2020	**16,922,525**	**$**	**55.12**	**$**
Exercisable at December 31, 2020	**16,922,525**	**$**	**55.12**	**$**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2020, were all 3.66 years. The aggregate intrinsic value of options exercised was $ million in 2019 and $94 million in 2018.

During 2020, we received $43 million in cash and realized a tax benefit of $9 million from the exercise of options. At December 31, 2020, all outstanding stock options were fully vested and there was no remaining compensation cost to be recorded.

Stock Unit Program—Generally, restricted stock units are granted annually under the provisions of the Plar 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 hc 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 p unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those un 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 cash payment of a dividend equivalent that is charged to retained earnings. Executive recipients receive an accrue reinvested dividend equivalent, subject to the terms and conditions of the award, 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, 2020:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Doll Total Fair Value
Outstanding at December 31, 2019	6,223,046	$ 55.99	
Granted	**2,890,840**	**57.40**	
Forfeited	**(127,181)**	**55.84**	
Issued	**(2,554,720)**	**50.16**	**$ 14**
Outstanding at December 31, 2020	**6,431,985**	**$ 58.94**	
Not Vested at December 31, 2020	**4,230,413**	**59.01**	

At December 31, 2020, the remaining unrecognized compensation cost from the unvested stock-settled units was $101 million, which will be recognized over a weighted-average period of 1.71 years, the longest period being 2.14 years. The weighted-average grant date fair value of stock unit awards granted during 2019 and 2018 was $67.77 and $52.45, respectively. The total fair value of stock units issued during 2019 and 2018 w $225 million and $154 million, respectively.

Cash-Settled
Cash settled executive restricted stock units granted in 2018 and 2019 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 regular scheduled vesting period. Compensation expense is initially measured using the average fair market value o 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. Beginning with executive restricted stock units granted in 2020 awards will be settled in stock.

The following summarizes our cash-settled stock unit activity for the year ended December 31, 2020:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Doll Total Fair Value
Outstanding at December 31, 2019	596,991	$ 64.54	
Granted	**24,437**	**41.59**	
Forfeited	**(5,622**	**40.01**	
Issued	**(1,191**	**40.20**	**$**
Outstanding at December 31, 2020	**614,615**	**$ 39.95**	
Not Vested at December 31, 2020	**121,696**	**39.95**	

At December 31, 2020, the remaining unrecognized compensation cost from the unvested cash-settled units was $1 million, which will be recognized over a weighted-average period of 1 year, the longest period being 1.12 years. The weighted-average grant date fair value of stock unit awards granted during 2019 and 2018 were $68.20 and $53.68, respectively. The total fair value of stock units issued during 2019 and 2018 were $ million and $1 million, respectively.

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 an 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 201 PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 5 with five years of service or five years after the grant date of the award, and restrictions do not lapse until th 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 awar 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 o dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future gran 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, 2020:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Doll Total Fair Value
Outstanding at December 31, 2019	2,024,824	$ 50.55	
Granted	**26,244**	**58.61**	
Forfeited	**-**		
Issued	**(314,340)**	**51.15**	**$ 1**
Outstanding at December 31, 2020	**1,736,728**	**$ 50.56**	
Not Vested at December 31, 2020	**3,191**	**$ 48.61**	

At December 31, 2020, 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 grant during 2019 and 2018 was $68.90 and $53.28, respectively. The total fair value of stock-settled PSUs issued during 2019 and 2018 was $25 million and $29 million, respectively.

Cash-Settled
In connection with and immediately following the separation of our Downstream businesses in 2012, grants new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, abse 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 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 t 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 performan 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 the terms and conditions of the award.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2020:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Doll… Total Fair Value
Outstanding at December 31, 2019	609,274	$ 64.54	
Granted	**1,491,098**	**58.61**	
Forfeited	**-**		
Settled	**(1,975,843)**	**58.54**	**$ 11**
Outstanding at December 31, 2020	**124,529**	**$ 39.95**	

At December 31, 2020, all outstanding cash-settled performance awards were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of cash-settled PSU granted during 2019 and 2018 was $68.90 and $53.28, respectively. The total fair value of cash-settled performance share awards settled during 2019 and 2018 was $171 million and $22 million, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after t conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near t 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 targe 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, t initial target PSU awards terminated at the end of the three-year performance period and were settled after t 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 restrict stock units that were either issued as part of our non-employee director compensation program for current an 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 dividend or divide equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2020:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Doll… Total Fair Value
Outstanding at December 31, 2019	991,908	$ 47.24	
Granted	**77,824**	**51.46**	
Cancelled	**(1,336)**	**23.09**	
Issued	**(98,297)**	**45.57**	**$**
Outstanding at December 31, 2020	**970,099**	**$ 47.78**	

At December 31, 2020, 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 2019 and 2018 was $63.58 and $62.01, respectively. The total fair value of awards issued during 2019 and 2018 was $11 million and $17 million, respectively.

Note 18—Income Taxes

Components of income tax expense (benefit) were:

	Millions of Dollars		
	2020	2019	2
Income Taxes			
Federal			
Current	$ **3**	18	
Deferred	**(625)**	(113)	
Foreign			
Current	**350**	2,545	3,
Deferred	**(70)**	(323)	(
State and local			
Current	**(4)**	148	
Deferred	**(139)**	(8)	
	$ **(485)**	2,267	3,

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 compone of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2020	
Deferred Tax Liabilities		
PP&E and intangibles	$ **7,744**	8
Inventory	**64**	
Other	**242**	
Total deferred tax liabilities	**8,050**	8
Deferred Tax Assets		
Benefit plan accruals	**540**	
Asset retirement obligations and accrued environmental costs	**2,262**	2
Investments in joint ventures	**1,653**	1
Other financial accruals and deferrals	**907**	
Loss and credit carryforwards	**8,904**	8
Other	**365**	
Total deferred tax assets	**14,631**	14
Less: valuation allowance	**(9,965)**	(10,
Total deferred tax assets net of valuation allowance	**4,666**	4
Net deferred tax liabilities	$ **3,384**	4

At December 31, 2020, noncurrent assets and liabilities included deferred taxes of $363 million and $3,747 million, respectively. At December 31, 2019, noncurrent assets and liabilities included deferred taxe of $184 million and $4,634 million, respectively.

At December 31, 2020, the loss and credit carryforward deferred tax assets were primarily related to U.S. foreign tax credit carryforwards of $7 billion and various jurisdictions net operating loss and credit carryforwards of $1.9 billion. If not utilized, U.S. foreign tax credits and net operating losses will begin to expire in 2021.

The following table shows a reconciliation of the beginning and ending deferred tax asset valuation allowanc
for 2020, 2019 and 2018:

		Millions of Dollars		
		2020	2019	20
Balance at January 1	$	**10,214**	3,040	1,25
Charged to expense (benefit)		**460**	(225)	(2
Other*		**(709)**	7,399	1,81
Balance at December 31	$	**9,965**	10,214	3,04

**Represents changes due to originating deferred tax asset that have no impact to our effective tax rate, acquisitions/dispositions/revisions and effect of translating foreign financial statements. Certain items in the prior year have been reclassed to conform with the current year presentation, with no impacts to beginning and ending balances.*

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. At December 31, 2020, we have maintained a valuation allowance with respect to substantially all U.S. foreign tax credit carryforwards as well as certain net operating loss carryforwards for various jurisdictions. During 2020, the valuation allowance movement charged to earnings primarily relates capital losses in Australia and to the fair value measurement of our Cenovus Energy common shares that are not expected to be realized. Other movements are primarily related to valuation allowances on expiring tax attributes. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects deferred tax assets, net of valuation allowances, 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 201
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, 2020, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,982 million. Deferred income tax
have not been provided on this amount, as we do not plan to initiate any action that would require the payme
of income taxes. The estimated amount of additional tax, primarily local withholding tax, that would be payable on this income if distributed is approximately $199 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2020, 2019 and 2018:

		Millions of Dollars		
		2020	2019	20
Balance at January 1	$	**1,177**	1,081	88
Additions based on tax positions related to the current year		**6**	9	26
Additions for tax positions of prior years		**67**	120	4
Reductions for tax positions of prior years		**(34)**	(22)	(7
Settlements		**(9)**	(9)	(3
Lapse of statute		**(1)**	(2)	(
Balance at December 31	$	**1,206**	1,177	1,08

Included in the balance of unrecognized tax benefits for 2020, 2019 and 2018 were $1,128 million, $1,100 million and $1,081 million, respectively, which, if recognized, would impact our effective tax rate. T 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. See Note 12—Contingencies and Commitments, for more information on the PDVSA settlement.

At December 31, 2020, 2019 and 2018, accrued liabilities for interest and penalties totaled $46 million, $42 million and $45 million, respectively, net of accrued income taxes. Interest and penalties resulted in a reduction to earnings of $4 million in 2020, a benefit to earnings of $3 million in 2019, and a benefit to earnings of $4 million in 2018, respectively.

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 (2019 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 federa statutory rate to the provision for income taxes, were:

		Millions of Dollars			Percent of Pre-Tax Income (Loss		
		2020	2019	2018	**2020**	2019	20
Income (loss) before income taxes							
United States	**$**	**(3,587)**	4,704	2,867	**114.2 %**	49.4	28
Foreign		**447**	4,820	7,106	**(14.2)**	50.6	71
	$	**(3,140)**	9,524	9,973	**100.0 %**	100.0	100
Federal statutory income tax	**$**	**(659)**	2,000	2,095	**21.0 %**	21.0	21
Non-U.S. effective tax rates		**194**	1,399	1,766	**(6.2)**	14.7	17
Tax Legislation		**-**	-	(10)	**-**	-	(0.
Australia disposition		**(349)**	-	-	**11.1**	-	
U.K. disposition		**-**	(732)	(150)	**-**	(7.7)	(1.
Recovery of outside basis		**(22)**	(77)	(21)	**0.7**	(0.8)	(0.
Adjustment to tax reserves		**18**	9	(4)	**(0.6)**	0.1	
Adjustment to valuation allowance		**460**	(225)	(26)	**(14.6)**	(2.4)	(0.
State income tax		**(112)**	123	135	**3.6**	1.3	1
Malaysia Deepwater Incentive		**-**	(164)	-	**-**	(1.7)	
Enhanced oil recovery credit		**(6)**	(27)	(99)	**0.2**	(0.3)	(1.
Other		**(9)**	(39)	(18)	**0.3**	(0.4)	(0.
	$	**(485)**	2,267	3,668	**15.5 %**	23.8	36

Our effective tax rate for 2020 was impacted by the disposition of our Australia-West assets as well as the valuation allowance related to the fair value measurement of our Cenovus Energy common shares. The Australia-West disposition generated a before-tax gain of $587 million with an associated tax benefit of $10 million and resulted in the de-recognition of deferred tax assets resulting in $92 million of tax expense. The disposition also generated an Australia capital loss tax benefit of $313 million which has been fully offset by valuation allowance. Due to changes in the fair market value of Cenovus Energy common shares, the valuation allowance was increased by $178 million to offset the expected capital loss.

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. tax benefit of approximately $285 million. The remaining U.S. capital loss has been recorded as a deferred ta asset fully offset with a valuation allowance. See Note 4—Asset Acquisitions and Dispositions, for additiona 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 i the U.K. and our overall income position, partially offset by our change in 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 4—Asset Acquisitions and Dispositions, for additional information on the disposition.

As a result of the COVID-19 pandemic and the resulting economic uncertainty, many countries in which we operate, including Australia, Canada, Norway and the U.S., have enacted responsive tax legislation. During the second quarter, Norway enacted legislation to accelerate the recovery of capital expenditures and allow immediate monetization of tax losses. As a result, in the second quarter of 2020, we recorded an increase to our net deferred tax liability of $120 million and a decrease to our accrued income and other taxes liability o $124 million. Legislation in other jurisdictions did not have a material impact to ConocoPhillips.

Note 19—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	Accumulat Oth Comprehensi Lo
December 31, 2017	$	(400)	(58)	(5,060)	(5,51
Other comprehensive income (loss)		39	-	(642)	(60
Cumulative effect of adopting ASU No. 2016-01*		-	58	-	5
December 31, 2018		(361)	-	(5,702)	(6,06
Other comprehensive income		51	-	695	74
Cumulative effect of adopting ASU No. 2018-02**		(40)	-	-	(4
December 31, 2019		(350)	-	(5,007)	(5,35
Other comprehensive income (loss)		**(75)**	**2**	**212**	**13**
December 31, 2020	**$**	**(425)**	**2**	**(4,795)**	**(5,21**

**We adopted ASU No. 2016-01, "Recognition and Measurement of Financial Assets and Liabilities," beginning January 1, 2018.*
***We adopted ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income," beginning Janua 1, 2019.*

During 2019, we recognized $483 million of foreign currency translation adjustments related to the completi of our sale of two ConocoPhillips U.K. subsidiaries. For additional information related to this disposition, se Note 4—Asset Acquisitions and Dispositions.

The following table summarizes reclassifications out of accumulated other comprehensive loss during the yea
ended December 31:

		Millions of Dollars	
		2020	20
Defined Benefit Plans	**$**	**72**	8
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	*$*	*13*	
See Note 17—Employee Benefit Plans, for additional information.			

Note 20—Cash Flow Information

		Millions of Dollars		
		2020	2019	20
Noncash Investing Activities				
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	**$**	**(116)**	205	39
Increase (decrease) in assets and liabilities acquired in a nonmonetary exchange*				
Accounts receivable		-	-	(4
Inventories		-	-	4
Investments and long-term receivables		-	-	1
PP&E		-	-	1,90
Other long-term assets		-	-	(
Accounts payable		-	-	
Accrued income and other taxes		-	-	4
Cash Payments				
Interest	**$**	**785**	810	77
Income taxes		**905**	2,905	2,97
Net Sales (Purchases) of Investments				
Short-term investments purchased	**$**	**(12,435)**	(4,902)	(1,95
Short-term investments sold		**12,015**	2,138	3,57
Investments and long-term receivables purchased		**(325)**	(146)	
Investments and long-term receivables sold		**87**	-	
	$	**(658)**	(2,910)	1,62

**See Note 4—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 settlemen
agreement related to an award issued by the ICC Tribunal in 2018. For more information on these settlemen
see Note 12—Contingencies and Commitments. We collected $262 million from Ecuador in 2018, as installment payments related to an agreement reached with Ecuador in 2017.

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 in 2018.

Note 21—Other Financial Information

		Millions of Dollars		
		2020	2019	20
Interest and Debt Expense				
Incurred				
Debt	$	**788**	799	83
Other		**73**	36	6
		861	835	90
Capitalized		**(55)**	(57)	(17
Expensed	$	**806**	778	73
Other Income (Loss)				
Interest income	$	**100**	166	9
Unrealized gains (losses) on Cenovus Energy common shares*		**(855)**	649	(43
Other, net		**246**	543	51
	$	**(509)**	1,358	17

See Note 6—Investment in Cenovus Energy, for additional information.

Research and Development Expenditures—expensed	$	**75**	82	7
Shipping and Handling Costs	$	**857**	1,008	1,07
Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**-**	-	
Lower 48		**-**	-	
Canada		**(7)**	5	(1
Europe, Middle East and North Africa		**(15)**	-	(2
Asia Pacific		**(11)**	31	
Other International		**2**	1	
Corporate and Other		**(31)**	21	2
	$	**(62)**	58	(1

		Millions of Dollars	
		2020	2
Properties, Plants and Equipment			
Proved properties	$	**94,312**	88,2
Unproved properties		**4,141**	3,9
Other		**3,653**	5,4
Gross properties, plants and equipment		**102,106**	97,7
Less: Accumulated depreciation, depletion and amortization		**(62,213)**	(55,4
Net properties, plants and equipment	$	**39,893**	42,2

**Excludes assets classified as held for sale at December 31, 2019. See Note 4—Asset Acquisitions and Dispositions, for additional informatio*

Note 22—Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employe
For disclosures on trusts for the benefit of employees, see Note 17—Employee Benefit Plans.

Significant transactions with our equity affiliates were:

		Millions of Dollars		
		2020	2019	20
Operating revenues and other income	$	**79**	89	9
Purchases		**-**	38	9
Operating expenses and selling, general and administrative expenses		**63**	65	6
Net interest income*		**(5)**	(13)	(1

**We paid interest to, or received interest from, various affiliates. See Note 5—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

Note 23—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		
		2020	2019	20
Revenue from contracts with customers	$	**13,662**	26,106	28,09
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative		**5,177**	6,558	8,21
Financial derivative contracts		**(55)**	(97)	10
Consolidated sales and other operating revenues	$	**18,784**	32,567	36,41

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 polic 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 24—Segment Disclosures and Related Information:

		Millions of Dollars		
		2020	2019	20
Revenue from Outside the Scope of ASC Topic 606 by Segment				
Lower 48	$	**3,966**	4,989	6,35
Canada		**727**	691	62
Europe, Middle East and North Africa		**484**	878	1,23
Physical contracts meeting the definition of a derivative	$	**5,177**	6,558	8,21

		Millions of Dollars		
		2020	2019	20
Revenue from Outside the Scope of ASC Topic 606 by Product				
Crude oil	$	**395**	804	1,11
Natural gas		**4,339**	5,313	6,73
Other		**443**	441	37
Physical contracts meeting the definition of a derivative	$	**5,177**	6,558	8,21

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 contracts which use prevailing market prices at the time of delivery, and sales under these contracts, the market-based variable consideration for each performance obligation (i.e., delivery of commodity) is allocated to ea 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 partia unsatisfied) as of the end of the reporting period.

Receivables and Contract Liabilities

Receivables from Contracts with Customers

At December 31, 2020, the "Accounts and notes receivable" line on our consolidated balance sheet included trade receivables of $1,827 million compared with $2,372 million at December 31, 2019, 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 sale 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 tra 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 th contract and are recorded as deferred revenue to be recognized as revenue when the customer can utilize an benefit from their right to use the license. Payments are received in installments over the construction perio

		Millions of Doll
Contract Liabilities		
At December 31, 2019	$	8
Contractual payments received		1
At December 31, 2020	$	9
Amounts Recognized in the Consolidated Balance Sheet at December 31, 2020		
Current liabilities	$	
Noncurrent liabilities		
	$	

We expect to recognize the contract liabilities as of December 31, 2020, as revenue during 2021 and 2022. There was no revenue recognized during the year ended December 31, 2020.

Note 24—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwi basis. We manage our operations through six operating segments, which are primarily defined by geographi region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International.

Corporate and Other represents income and 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 a prices that approximate market.

Effective with the third quarter of 2020, we restructured our segments to align with changes to our internal organization. The Middle East business was realigned from the Asia Pacific and Middle East segment to the Europe and North Africa segment. The segments have been renamed the Asia Pacific segment and the Europ Middle East and North Africa segment. We have revised segment information disclosures and segment performance metrics presented within our results of operations for the current and prior comparative periods.

Analysis of Results by Operating Segment

		Millions of Dollars		
		2020	2019	20
Sales and Other Operating Revenues				
Alaska	$	**3,408**	5,483	5,74
Intersegment eliminations		**(11)**	-	
Alaska		**3,397**	5,483	5,74
Lower 48		**9,872**	15,514	17,02
Intersegment eliminations		**(51)**	(46)	(4
Lower 48		**9,821**	15,468	16,98
Canada		**1,666**	2,910	3,18
Intersegment eliminations		**(405)**	(1,141)	(1,16
Canada		**1,261**	1,769	2,02
Europe, Middle East and North Africa		**1,919**	5,101	6,63
Intersegment eliminations		**(2)**	-	
Europe, Middle East and North Africa		**1,917**	5,101	6,63
Asia Pacific		**2,363**	4,525	4,86
Other International		**7**	-	
Corporate and Other		**18**	221	16
Consolidated sales and other operating revenues	$	**18,784**	32,567	36,41

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		
		2020	2019	20
Depreciation, Depletion, Amortization and Impairments				
Alaska	$	**996**	805	76
Lower 48		**3,358**	3,224	2,37
Canada		**342**	232	32
Europe, Middle East and North Africa		**775**	887	1,04
Asia Pacific		**809**	1,285	1,38
Other International		**-**	-	
Corporate and Other		**54**	62	10
Consolidated depreciation, depletion, amortization and impairments	$	**6,334**	6,495	5,98
Equity in Earnings of Affiliates				
Alaska	$	**(7)**	7	
Lower 48		**(11)**	(159)	
Canada		**-**	-	
Europe, Middle East and North Africa		**311**	470	74
Asia Pacific		**137**	461	32
Other International		**2**	-	
Corporate and Other		**-**	-	
Consolidated equity in earnings of affiliates	$	**432**	779	1,07
Income Tax Provision (Benefit)				
Alaska	$	**(256)**	472	37
Lower 48		**(378)**	137	47
Canada		**(185)**	(43)	(9
Europe, Middle East and North Africa		**136**	1,425	2,25
Asia Pacific		**294**	501	72
Other International		**(20)**	8	3
Corporate and Other		**(76)**	(233)	(10
Consolidated income tax provision (benefit)	$	**(485)**	2,267	3,66
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$	**(719)**	1,520	1,81
Lower 48		**(1,122)**	436	1,74
Canada		**(326)**	279	6
Europe, Middle East and North Africa		**448**	3,170	2,59
Asia Pacific		**962**	1,483	1,34
Other International		**(64)**	263	36
Corporate and Other		**(1,880)**	38	(1,66
Consolidated net income (loss) attributable to ConocoPhillips	$	**(2,701)**	7,189	6,25

		Millions of Dollars		
		2020	2019	20
Investments in and Advances to Affiliates				
Alaska	$	**62**	83	8
Lower 48		**25**	35	37
Canada		**-**	-	
Europe, Middle East and North Africa		**918**	1,070	1,31
Asia Pacific		**6,705**	7,265	7,56
Other International		**-**	-	
Corporate and Other		**-**	-	
Consolidated investments in and advances to affiliates	$	**7,710**	8,453	9,34
Total Assets				
Alaska	$	**14,623**	15,453	14,64
Lower 48		**11,932**	14,425	14,88
Canada		**6,863**	6,350	5,74
Europe, Middle East and North Africa		**8,756**	9,269	11,27
Asia Pacific		**11,231**	13,568	14,75
Other International		**226**	285	8
Corporate and Other		**8,987**	11,164	8,57
Consolidated total assets	$	**62,618**	70,514	69,98
Capital Expenditures and Investments				
Alaska	$	**1,038**	1,513	1,29
Lower 48		**1,881**	3,394	3,18
Canada		**651**	368	47
Europe, Middle East and North Africa		**600**	708	87
Asia Pacific		**384**	584	71
Other International		**121**	8	
Corporate and Other		**40**	61	19
Consolidated capital expenditures and investments	$	**4,715**	6,636	6,75
Interest Income and Expense				
Interest income				
Alaska	$	**-**	-	
Lower 48		**-**	-	
Canada		**-**	-	
Europe, Middle East and North Africa		**5**	11	12
Asia Pacific		**7**	6	
Other International		**-**	-	
Corporate and Other		**88**	149	80
Interest and debt expense				
Corporate and Other	$	**806**	778	73
Sales and Other Operating Revenues by Product				
Crude oil	$	**9,736**	18,482	19,57
Natural gas		**6,427**	8,715	10,72
Natural gas liquids		**528**	814	1,11
Other*		**2,093**	4,556	5,01
Consolidated sales and other operating revenues by product	$	**18,784**	32,567	36,41

**Includes LNG and bitumen.*

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
	2020	2019	2018	**2020**	2019	20
United States	$ **13,230**	21,159	22,740	**24,034**	26,566	26,83
Australia and Timor-Leste	**605**	1,647	1,798	**6,676**	7,228	9,30
Canada	**1,261**	1,769	2,024	**6,385**	5,769	5,33
China	**460**	772	836	**1,491**	1,447	1,38
Indonesia	**689**	875	886	**464**	605	66
Libya	**155**	1,103	1,142	**670**	668	67
Malaysia	**610**	1,230	1,346	**1,501**	1,871	2,32
Norway	**1,426**	2,349	2,886	**5,294**	5,258	5,58
United Kingdom	**336**	1,649	2,606	**1**	2	1,58
Other foreign countries	**12**	14	153	**1,087**	1,308	1,34
Worldwide consolidated	$ **18,784**	32,567	36,417	**47,603**	50,722	55,03

(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.

Note 25—Acquisition of Concho Resources Inc.

On October 18, 2020, we entered into a definitive agreement to acquire Concho in an all-stock transaction. The transaction closed on January 15, 2021 and as defined under the terms of the transaction agreement, each share of Concho common stock was exchanged at a fixed ratio of 1.46 for shares of ConocoPhillips common stock, for total consideration of $13.1 billion. This resulted in issuance of 286 million shares, representing approximately 21 percent of the outstanding shares of ConocoPhillips common stock upon completion of the transaction.

We also assumed Concho's outstanding debt of $3.9 billion in aggregate principal amount, recorded at fair value of $4.7 billion on the transaction closing date. On December 7, 2020, we launched a debt exchange of which settled on February 8, 2021, for 98 percent of Concho's historical notes. The historical notes issued by Concho were exchanged for new notes issued by ConocoPhillips, which are fully and unconditionally guaranteed by ConocoPhillips Company. For further discussion about the debt exchange, see Note 10 – Deb

As of the acquisition date, January 15, 2021, the fair value of consideration transferred is summarized below

Total Consideration		
Number of shares of Concho common stock issued and outstanding (in thousands)*		194,2
Number of shares of Concho stock awards outstanding (in thousands)*		1,5
Number of shares exchanged		195,8
Exchange ratio		1.
Additional shares of ConocoPhillips common stock issued as consideration (in thousands)		285,9
Average price per share of ConocoPhillips common stock**	$	45.90
Total Consideration (Millions)	**$**	**13,1**

**Outstanding as of January 15, 2021.*
***Based on the ConocoPhillips average stock price on January 15, 2021.*

The transaction will be accounted for as a business combination under the acquisition method of accounting. The total purchase price will be allocated to identifiable assets acquired and the liabilities assumed based on their fair values as of the closing date. We are currently in the process of finalizing the initial accounting for this transaction and provisional fair value measurements will be made in the first quarter of 2021. We may adjust the measurements in subsequent periods, up to one year from the acquisition date as we identify additional information to complete the necessary analysis.

Oil and Gas Operations (Unaudited)

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 sha 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 disclosure reported elsewhere in this report. Our disclosures by geographic area include the U.S., Canada, Europe, Asi Pacific/Middle East (inclusive of equity affiliates), and Africa.

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, the our applicable reserve quantities would decline. At December 31, 2020, approximately 6 percent of our tota proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 8 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

<u>Reserves Governance</u>

The recording and reporting of proved reserves are governed by criteria established by regulations of the SE 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 d forward, from known reservoirs, and under existing economic conditions, operating methods, and governme 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 cos 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 prove 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 reser
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 da
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 Manag
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 o
technical issues throughout the year. All of our proved reserves held by consolidated companies and our sha
of equity affiliates have been estimated by ConocoPhillips.

During 2020, our processes and controls used to assess over 90 percent of proved reserves as of December 3
2020, 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 balanc
calculations, reservoir simulation models, well performance data, operating procedures and relevant econom
criteria. Management's intent in retaining D&M to review its processes and controls was to provide objecti
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, 2020, proved reserves for the properties review
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. Th
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 internationa
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	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2017	937	707	1,644	1	296	185	196
Revisions	72	(90)	(18)	2	24	6	5
Improved recovery	2	-	2	-	-	-	-
Purchases	233	1	234	-	-	-	-
Extensions and discoveries	48	179	227	2	2	1	-
Production	(59)	(82)	(141)	(1)	(40)	(33)	(13
Sales	-	(12)	(12)	-	(36)	-	-
End of 2018	1,233	703	1,936	4	246	159	188
Revisions	40	(36)	4	(1)	18	(5)	23
Improved recovery	7	-	7	-	-	-	-
Purchases	-	1	1	-	-	-	-
Extensions and discoveries	25	226	251	2	-	11	-
Production	(74)	(95)	(169)	-	(36)	(31)	(14
Sales	-	(2)	(2)	-	(30)	-	-
End of 2019	1,231	797	2,028	5	198	134	197
Revisions	(297)	(126)	(423)	(2)	4	(4)	(3
Improved recovery	-	-	-	-	-	3	-
Purchases	-	5	5	3	-	-	-
Extensions and discoveries	10	108	118	3	-	-	-
Production	(65)	(77)	(142)	(2)	(28)	(25)	(3
Sales	-	(14)	(14)	(1)	-	-	-
End of 2020	879	693	1,572	6	174	108	191
Equity affiliates							
End of 2017	-	-	-	-	-	83	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	78	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	73	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	68	-
Total company							
End of 2017	937	707	1,644	1	296	268	196
End of 2018	1,233	703	1,936	4	246	237	188
End of 2019	1,231	797	2,028	5	198	207	197
End of 2020	879	693	1,572	6	174	176	191

Years Ended December 31	Crude Oil						
	Millions of Barrels						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa
Developed							
Consolidated operations							
End of 2017	828	315	1,143	1	190	121	196
End of 2018	1,058	346	1,404	2	192	113	185
End of 2019	1,048	334	1,382	3	149	94	181
End of 2020	765	263	1,028	6	129	77	175
Equity affiliates							
End of 2017	-	-	-	-	-	83	-
End of 2018	-	-	-	-	-	78	-
End of 2019	-	-	-	-	-	73	-
End of 2020	-	-	-	-	-	68	-
Undeveloped							
Consolidated operations							
End of 2017	109	392	501	-	106	64	-
End of 2018	175	357	532	2	54	46	3
End of 2019	183	463	646	2	49	40	16
End of 2020	114	430	544	-	45	31	16
Equity affiliates							
End of 2017	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2020, included:

- *Revisions*: In 2020, Alaska downward revisions were primarily driven by lower prices of 243 million barrels development plan changes of 54 million barrels. Downward revisions in Lower 48 were due to lower prices million barrels and development timing for specific well locations from unconventional plays of 82 million partially offset by upward technical revisions and additional infill drilling in the unconventional plays of 45 barrels.

  In 2019, Alaska upward revisions were due to cost and technical revisions of 74 million barrels, partially off downward price revisions of 34 million barrels. Upward revisions in Europe and Africa were primarily due drilling and technical revisions. Downward revisions in Lower 48 were due to changes in development timi specific well locations from the unconventional plays of 71 million barrels and price revisions of 22 million partially offset by upward revisions related to infill drilling and improved well performance of 57 million ba

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific locations from the unconventional plays and are more than offset by increases in planned well locations in th unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to d timing were partially offset by higher prices. Revisions in Alaska, Europe and Asia Pacific/Middle East were due to higher prices.

- *Purchases:* In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acqu

- *Extensions and discoveries*: In 2020, extensions and discoveries in Lower 48 were due to planned developm
specific well locations from the unconventional plays which more than offset the decreases resulting from d
plan timing in the revisions category.

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locat
the unconventional plays which more than offset the decreases in the revisions category. In Asia Pacific/Mi
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
specific well locations from the unconventional plays. Extensions and discoveries in Alaska were driven by
success in Western North Slope.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Europe sales were due to t
disposition of a subsidiary that held 16.5 percent of our 24 percent interest in the Clair Field in the U.K.

Years Ended December 31	Natural Gas Liquids					
	Millions of Barrels					
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East
Developed and Undeveloped						
Consolidated operations						
End of 2017	106	224	330	1	18	5
Revisions	5	(25)	(20)	-	1	(1
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	69	69	-	1	-
Production	(5)	(25)	(30)	-	(3)	(1
Sales	-	(21)	(21)	-	-	-
End of 2018	106	222	328	1	17	3
Revisions	(1)	(11)	(12)	-	3	(1
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	62	62	1	-	-
Production	(5)	(28)	(33)	-	(3)	(1
Sales	-	-	-	-	(4)	-
End of 2019	100	245	345	2	13	1
Revisions	-	(26)	(26)	-	1	(1
Improved recovery	-	-	-	-	-	-
Purchases	-	2	2	2	-	-
Extensions and discoveries	-	41	41	1	-	-
Production	(6)	(27)	(33)	(1)	(2)	-
Sales	-	(5)	(5)	-	-	-
End of 2020	94	230	324	4	12	-
Equity affiliates						
End of 2017	-	-	-	-	-	45
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3
Sales	-	-	-	-	-	-
End of 2018	-	-	-	-	-	42
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3
Sales	-	-	-	-	-	-
End of 2019	-	-	-	-	-	39
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3
Sales	-	-	-	-	-	-
End of 2020	-	-	-	-	-	36
Total company						
End of 2017	106	224	330	1	18	50
End of 2018	106	222	328	1	17	45
End of 2019	100	245	345	2	13	40
End of 2020	94	230	324	4	12	36

Years Ended December 31	Natural Gas Liquids					
	Millions of Barrels					
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East
Developed						
Consolidated operations						
End of 2017	106	101	207	1	16	2
End of 2018	106	97	203	-	15	3
End of 2019	100	99	199	1	10	1
End of 2020	94	83	177	4	9	-
Equity affiliates						
End of 2017	-	-	-	-	-	45
End of 2018	-	-	-	-	-	42
End of 2019	-	-	-	-	-	39
End of 2020	-	-	-	-	-	36
Undeveloped						
Consolidated operations						
End of 2017	-	123	123	-	2	3
End of 2018	-	125	125	1	2	-
End of 2019	-	146	146	1	3	-
End of 2020	-	147	147	-	3	-
Equity affiliates						
End of 2017	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-
End of 2019	-	-	-	-	-	-
End of 2020	-	-	-	-	-	-

Notable changes in proved NGL reserves in the three years ended December 31, 2020, included:

- *Revisions*: In 2020, downward revisions in Lower 48 were due to lower prices of 33 million barrels and deve timing for specific well locations from unconventional plays of 20 million barrels, partially offset by upward revisions and additional infill drilling in the unconventional plays of 27 million barrels.

  In 2019, downward revisions in Lower 48 were due to changes in development timing for specific well locat the unconventional plays of 32 million barrels and price revisions of 11 million barrels, partially offset by up 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 locations from the unconventional plays and are more than offset by increases in planned well locations in th unconventional plays in the extensions and discoveries category.

- *Extensions and discoveries*: In 2020, extensions and discoveries in Lower 48 were due to planned developm specific well locations from the unconventional plays which more than offset the decreases in the revisions c

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locat 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 specific well locations from the unconventional plays.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Lower 48 sales were prim the disposition of our interests in the Barnett.

Years Ended December 31	Natural Gas						
	Billions of Cubic Feet						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2017	2,320	2,533	4,853	11	1,217	1,298	224
Revisions	150	(283)	(133)	9	86	4	-
Improved recovery	-	-	-	-	-	-	-
Purchases	335	1	336	-	-	-	-
Extensions and discoveries	2	527	529	11	110	23	-
Production	(71)	(237)	(308)	(5)	(188)	(246)	(10
Sales	-	(223)	(223)	-	(13)	-	-
End of 2018	2,736	2,318	5,054	26	1,212	1,079	214
Revisions	30	(113)	(83)	(2)	160	147	21
Improved recovery	-	-	-	-	-	-	-
Purchases	-	2	2	-	-	-	-
Extensions and discoveries	7	483	490	23	-	1	-
Production	(85)	(252)	(337)	(4)	(178)	(250)	(11
Sales	-	(7)	(7)	-	(298)	-	-
End of 2019	2,688	2,431	5,119	43	896	977	224
Revisions	(607)	(439)	(1,046)	(15)	39	103	2
Improved recovery	-	-	-	-	-	-	-
Purchases	-	74	74	29	-	-	-
Extensions and discoveries	-	304	304	33	2	-	-
Production	(85)	(231)	(316)	(16)	(112)	(171)	(2
Sales	-	(39)	(39)	-	-	(58)	-
End of 2020	1,996	2,100	4,096	74	825	851	224
Equity affiliates							
End of 2017	-	-	-	-	-	4,303	-
Revisions	-	-	-	-	-	280	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	362	-
Production	-	-	-	-	-	(381)	-
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	4,564	-
Revisions	-	-	-	-	-	(7)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	252	-
Production	-	-	-	-	-	(388)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	4,421	-
Revisions	-	-	-	-	-	(382)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	2	-
Extensions and discoveries	-	-	-	-	-	78	-
Production	-	-	-	-	-	(395)	-
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	3,724	-
Total company							
End of 2017	2,320	2,533	4,853	11	1,217	5,601	224
End of 2018	2,736	2,318	5,054	26	1,212	5,643	214
End of 2019	2,688	2,431	5,119	43	896	5,398	224
End of 2020	1,996	2,100	4,096	74	825	4,575	224

Years Ended December 31	Natural Gas						
	Billions of Cubic Feet						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
Developed							
Consolidated operations							
End of 2017	2,310	1,597	3,907	11	997	945	224
End of 2018	2,720	1,427	4,147	17	1,052	758	214
End of 2019	2,601	1,398	3,999	30	697	843	224
End of 2020	1,961	1,051	3,012	74	598	806	224
Equity affiliates							
End of 2017	-	-	-	-	-	4,044	-
End of 2018	-	-	-	-	-	4,059	-
End of 2019	-	-	-	-	-	3,898	-
End of 2020	-	-	-	-	-	3,293	-
Undeveloped							
Consolidated operations							
End of 2017	10	936	946	-	220	353	-
End of 2018	16	891	907	9	160	321	-
End of 2019	87	1,033	1,120	13	199	134	-
End of 2020	35	1,049	1,084	-	227	45	-
Equity affiliates							
End of 2017	-	-	-	-	-	259	-
End of 2018	-	-	-	-	-	505	-
End of 2019	-	-	-	-	-	523	-
End of 2020	-	-	-	-	-	431	-

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclo primarily because the quantities above include gas consumed in production operations. Quantities consumed in prod operations are not significant in the periods presented. The value of net production consumed in operations is not ref 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 2,286 Bcf, 3,141 Bcf, and 3,131 Bcf as of Dece 2020, 2019 and 2018, respectively. These volumes are not included in the calculation of our Standardized Measure c 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, 2020, included:

- *Revisions*: In 2020, downward revisions in Alaska were primarily due to lower prices. In Lower 48, downwa revisions of 372 Bcf were due to lower prices and 154 Bcf were due to development timing for specific well from unconventional plays, partially offset by technical revisions of 87 Bcf. Downward revisions in our equi in Asia Pacific/Middle East were due to lower prices of 426 Bcf, partially offset by performance revisions of Upward revisions in our consolidated operations in Asia Pacific/Middle East were due to technical revisions and price revisions of 15 Bcf.

  In 2019, upward revisions in Europe were due to technical and cost revisions. In Asia Pacific/Middle East u revisions were primarily due to the Indonesia Corridor PSC term extension. Downward revisions in Lower due to changes in development timing for specific well locations from the unconventional plays of 207 Bcf a revisions of 125 Bcf, partially offset by upward revisions related to infill drilling and improved well perform 219 Bcf.

In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific locations from the unconventional plays and are more than offset by increases in planned well locations in th unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to d timing were partially offset by higher prices. Revisions in Alaska, Canada, Europe and our equity affiliates Pacific/Middle East were primarily due to higher prices.

- *Purchases*: In 2020, Canada purchases were due to the acquisition of additional Montney acreage.

  In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acquisitions.

- *Extensions and discoveries*: In 2020, extensions and discoveries in Lower 48 were due to planned developm specific well locations from the unconventional plays which more than offset the decreases resulting from d plan timing in the revisions category. Extensions and discoveries in Canada were primarily driven by ongoin successes in Montney.

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locat the unconventional plays which more than offset the decreases in the revisions category. Extensions and dis 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 specific well locations from the unconventional plays. Extensions and discoveries in Canada, Europe and ou affiliates in Asia Pacific/Middle East were primarily driven by ongoing drilling successes in Montney, Norw APLNG, respectively.

- *Sales*: In 2020, Asia Pacific/Middle East sales represent the disposition of the Australia-West assets.

  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.

Years Ended December 31	Bitumen
	Millions of Barre
	Can
Developed and Undeveloped	
Consolidated operations	
End of 2017	2
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	
End of 2018	2
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	
End of 2019	2
Revisions	(
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	
End of 2020	3
Equity affiliates	
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	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2020	
Total company	
End of 2017	2
End of 2018	2
End of 2019	2
End of 2020	3

Years Ended December 31	Bitumen
	Millions of Barre
	Can
Developed	
Consolidated operations	
End of 2017	1
End of 2018	1
End of 2019	1
End of 2020	1
Equity affiliates	
End of 2017	
End of 2018	
End of 2019	
End of 2020	
Undeveloped	
Consolidated operations	
End of 2017	
End of 2018	
End of 2019	
End of 2020	2
Equity affiliates	
End of 2017	
End of 2018	
End of 2019	
End of 2020	

Notable changes in proved bitumen reserves in the three years ended December 31, 2020, included:

- *Revisions*: In 2020, downward revisions in Canada were due to changes in development timing for specific pad locations from the Surmont development program of 12 million barrels with the remaining revisions primarily related to lower prices.

  In 2019, upward revisions in Canada were due to technical revisions in Surmont of 70 million barre 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, revisions were primarily due to higher prices at Surmont.

- *Extensions and discoveries*: In 2020, extensions and discoveries in Canada were primarily due to planned development to add specific pad locations from the Surmont development program, which more than offset the decrease in the revisions category.

  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 catego of 31 million barrels.

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	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2017	1,430	1,353	2,783	254	517	406	233
Revisions	102	(161)	(59)	12	40	5	6
Improved recovery	2	-	2	-	-	-	-
Purchases	289	1	290	-	-	-	-
Extensions and discoveries	48	335	383	4	21	6	-
Production	(76)	(146)	(222)	(25)	(75)	(75)	(15
Sales	-	(70)	(70)	-	(38)	-	-
End of 2018	1,795	1,312	3,107	245	465	342	224
Revisions	44	(67)	(23)	36	48	19	26
Improved recovery	7	-	7	-	-	-	-
Purchases	-	2	2	-	-	-	-
Extensions and discoveries	26	368	394	38	-	11	-
Production	(93)	(165)	(258)	(23)	(68)	(74)	(16
Sales	-	(3)	(3)	-	(85)	-	-
End of 2019	1,779	1,447	3,226	296	360	298	234
Revisions	(398)	(226)	(624)	(20)	12	13	(3
Improved recovery	-	-	-	-	-	3	-
Purchases	-	19	19	10	-	-	-
Extensions and discoveries	10	200	210	95	-	-	-
Production	(85)	(142)	(227)	(25)	(49)	(55)	(3
Sales	-	(25)	(25)	(1)	-	(10)	-
End of 2020	1,306	1,273	2,579	355	323	249	228
Equity affiliates							
End of 2017	-	-	-	-	-	845	-
Revisions	-	-	-	-	-	46	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	60	-
Production	-	-	-	-	-	(71)	-
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	880	-
Revisions	-	-	-	-	-	(1)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	42	-
Production	-	-	-	-	-	(73)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	848	-
Revisions	-	-	-	-	-	(63)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	13	-
Production	-	-	-	-	-	(73)	-
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	725	-
Total company							
End of 2017	1,430	1,353	2,783	254	517	1,251	233
End of 2018	1,795	1,312	3,107	245	465	1,222	224
End of 2019	1,779	1,447	3,226	296	360	1,146	234
End of 2020	1,306	1,273	2,579	355	323	974	228

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
Developed							
Consolidated operations							
End of 2017	1,319	682	2,001	158	372	281	233
End of 2018	1,617	681	2,298	160	382	244	221
End of 2019	1,582	666	2,248	197	275	236	218
End of 2020	1,186	521	1,707	140	238	211	212
Equity affiliates							
End of 2017	-	-	-	-	-	802	-
End of 2018	-	-	-	-	-	796	-
End of 2019	-	-	-	-	-	761	-
End of 2020	-	-	-	-	-	653	-
Undeveloped							
Consolidated operations							
End of 2017	111	671	782	96	145	125	-
End of 2018	178	631	809	85	83	98	3
End of 2019	197	781	978	99	85	62	16
End of 2020	120	752	872	215	85	38	16
Equity affiliates							
End of 2017	-	-	-	-	-	43	-
End of 2018	-	-	-	-	-	84	-
End of 2019	-	-	-	-	-	87	-
End of 2020	-	-	-	-	-	72	-

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six MCF of natural gas co
one BOE.

Proved Undeveloped Reserves

The following table shows changes in total proved undeveloped reserves for 2020:

	Proved Undevelope
	Millions o Oi
End of 2019	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Sales	
Transfers to proved developed	
End of 2020	

Downward revisions were driven by changes in development timing of 137 MMBOE primarily in North America an
prices of 103 MMBOE, partially offset by upward revisions for infill drilling of 35 MMBOE primarily in Lower 48 a

Extensions and discoveries were largely driven by an addition of 196 MMBOE in Lower 48 for the continued devel
unconventional plays. The remaining extensions and discoveries were driven by the continued development planned
Asia Pacific/Middle East and Alaska.

Transfers to proved developed reserves were driven by the ongoing development of our assets. Approximately half o
transfers were from the development of our Lower 48 unconventional plays. The remainder of transfers were from d
across the Alaska, Asia Pacific/Middle East and Europe regions.

At December 31, 2020, our PUDs represented 29 percent of total proved reserves, compared with 25 percent at Dece
2019. Costs incurred for the year ended December 31, 2020, relating to the development of PUDs were $3.2 billion.
portion of our costs incurred each year relates to development projects where the PUDs will be converted to proved develop
in future years.

At the end of 2020, more than 97 percent of total PUDs were under development or scheduled for development withi
years of initial disclosure, including our PUDs in North America. The remaining PUDs are in major development ar
are currently producing and within our Asia Pacific/Middle East geographic area.

Results of Operations

The company's results of operations from oil and gas activities for the years 2020, 2019 and 2018 are shown in the f
tables. Non-oil and gas activities, such as pipeline and marine operations, LNG operations, crude oil and gas market
activities, and the profit element of transportation operations in which we have an ownership interest are excluded.
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 r
interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a f
delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a
delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sa
hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used i
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 othe
miscellaneous expenses.

Results of Operations

Year Ended December 31, 2020		Millions of Dollars						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Area
Consolidated operations								
Sales	$ 2,944	3,421	6,365	230	1,560	1,717	129	-
Transfers	4	-	4	-	-	191	-	-
Transportation	(587)	-	(587)	-	-	(19)	-	-
Other revenues	(1)	(20)	(21)	40	(21)	576	11	10
Total revenues	2,360	3,401	5,761	270	1,539	2,465	140	10
Production costs excluding taxes	1,058	1,399	2,457	366	417	478	21	2
Taxes other than income taxes	296	263	559	16	30	42	3	1
Exploration expenses	1,099	73	1,172	40	52	71	13	108
Depreciation, depletion and amortization	840	2,544	3,384	335	755	808	8	-
Impairments	-	804	804	3	5	-	-	-
Other related expenses	46	5	51	5	(58)	(25)	(29)	2
Accretion	72	46	118	8	73	33	-	-
	(1,051)	(1,733)	(2,784)	(503)	265	1,058	124	(103
Income tax provision (benefit)	(271)	(430)	(701)	(191)	116	277	88	(20
Results of operations	$ (780)	(1,303)	(2,083)	(312)	149	781	36	(83
Equity affiliates								
Sales	$ -	-	-	-	-	483	-	-
Transfers	-	-	-	-	-	1,205	-	-
Transportation	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	8	-	-
Total revenues	-	-	-	-	-	1,696	-	-
Production costs excluding taxes	-	-	-	-	-	289	-	-
Taxes other than income taxes	-	-	-	-	-	502	-	-
Exploration expenses	-	-	-	-	-	20	-	-
Depreciation, depletion and amortization	-	-	-	-	-	569	-	-
Impairments	-	-	-	-	-	-	-	-
Other related expenses	-	-	-	-	-	(2)	-	-
Accretion	-	-	-	-	-	15	-	-
	-	-	-	-	-	303	-	-
Income tax provision (benefit)	-	-	-	-	-	39	-	-
Results of operations	$ -	-	-	-	-	264	-	-

Year Ended December 31, 2019		Millions of Dollars								
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	To
Consolidated operations										
Sales	$	4,883	6,356	11,239	709	3,207	3,032	919	-	19,1
Transfers		4	-	4	-	-	449	-	-	4
Transportation		(629)	-	(629)	-	-	(41)	-	-	(6
Other revenues		61	78	139	86	1,785	12	101	326	2,4
Total revenues		4,319	6,434	10,753	795	4,992	3,452	1,020	326	21,3
Production costs excluding taxes		1,235	1,578	2,813	380	741	619	70	(8)	4,6
Taxes other than income taxes		308	437	745	18	32	54	3	(2)	8
Exploration expenses		97	430	527	32	69	80	5	33	7
Depreciation, depletion and amortization		700	2,804	3,504	230	842	1,172	37	-	5,7
Impairments		-	402	402	2	1	-	-	-	4
Other related expenses		(12)	116	104	(38)	(42)	58	22	10	1
Accretion		62	49	111	7	142	43	-	-	3
		1,929	618	2,547	164	3,207	1,426	883	293	8,5
Income tax provision (benefit)		444	147	591	(74)	591	458	833	7	2,4
Results of operations	$	1,485	471	1,956	238	2,616	968	50	286	6,1
Equity affiliates										
Sales	$	-	-	-	-	-	599	-	-	5
Transfers		-	-	-	-	-	2,229	-	-	2,2
Transportation		-	-	-	-	-	-	-	-	
Other revenues		-	-	-	-	-	31	-	-	
Total revenues		-	-	-	-	-	2,859	-	-	2,8
Production costs excluding taxes		-	-	-	-	-	335	-	-	3
Taxes other than income taxes		-	-	-	-	-	820	-	-	8
Exploration expenses		-	-	-	-	-	-	-	-	
Depreciation, depletion and amortization		-	-	-	-	-	579	-	-	5
Impairments		-	-	-	-	-	-	-	-	
Other related expenses		-	-	-	-	-	11	-	-	
Accretion		-	-	-	-	-	16	-	-	
		-	-	-	-	-	1,098	-	-	1,0
Income tax provision (benefit)		-	-	-	-	-	170	-	-	1
Results of operations	$	-	-	-	-	-	928	-	-	9

Year Ended December 31, 2018		Millions of Dollars							
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Ot Ar
Consolidated operations									
Sales	$	4,816	6,573	11,389	582	4,449	3,177	950	
Transfers		5	-	5	-	-	545	-	
Transportation		(722)	-	(722)	-	-	(45)	-	
Other revenues		335	213	548	164	737	6	110	4
Total revenues		4,434	6,786	11,220	746	5,186	3,683	1,060	4
Costs									
Production costs excluding taxes		964	1,533	2,497	417	856	646	62	
Taxes other than income taxes		357	432	789	21	33	95	3	
Exploration expenses		59	176	235	21	57	43	(4)	
Depreciation, depletion and amortization		616	2,279	2,895	313	1,070	1,186	33	
Impairments		1	64	65	9	(78)	14	-	
Other related expenses		16	63	79	56	(62)	(19)	1	
Accretion		56	51	107	7	178	39	-	
		2,365	2,188	4,553	(98)	3,132	1,679	965	4
Income tax provision (benefit)		419	466	885	(114)	1,354	683	926	
Results of operations	$	1,946	1,722	3,668	16	1,778	996	39	4
Equity affiliates									
Sales	$	-	-	-	-	-	758	-	
Transfers		-	-	-	-	-	2,018	-	
Transportation		-	-	-	-	-	-	-	
Other revenues		-	-	-	-	-	(6)	-	
Total revenues		-	-	-	-	-	2,770	-	
Costs									
Production costs excluding taxes		-	-	-	-	-	321	-	
Taxes other than income taxes		-	-	-	-	-	804	-	
Exploration expenses		-	-	-	-	-	-	-	
Depreciation, depletion and amortization		-	-	-	-	-	640	-	
Impairments		-	-	-	-	-	-	-	
Other related expenses		-	-	-	-	-	(4)	-	
Accretion		-	-	-	-	-	15	-	
		-	-	-	-	-	994	-	
Income tax provision (benefit)		-	-	-	-	-	103	-	
Results of operations	$	-	-	-	-	-	891	-	

Statistics

Net Production	2020	2019	20
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**181**	202	1
Lower 48	**213**	266	2
United States	**394**	468	4
Canada	**6**	1	
Europe	**78**	100	1
Asia Pacific	**69**	85	
Africa	**8**	38	
Total consolidated operations	**555**	692	6
Equity affiliates—Asia Pacific/Middle East	**13**	13	
Total company	**568**	705	6
*Greater Prudhoe Area (Alaska)**	***68***	*66*	
Natural Gas Liquids			
Consolidated operations			
Alaska	**16**	15	
Lower 48	**74**	81	
United States	**90**	96	
Canada	**2**	-	
Europe	**4**	7	
Asia Pacific	**1**	4	
Total consolidated operations	**97**	107	
Equity affiliates—Asia Pacific/Middle East	**8**	8	
Total company	**105**	115	1
*Greater Prudhoe Area (Alaska)**	***15***	*15*	
Bitumen			
Consolidated operations—Canada	**55**	60	
Total company	**55**	60	
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**10**	7	
Lower 48	**585**	622	5
United States	**595**	629	6
Canada	**40**	9	
Europe	**270**	447	4
Asia Pacific	**429**	637	6
Africa	**5**	31	
Total consolidated operations	**1,339**	1,753	1,7
Equity affiliates—Asia Pacific/Middle East	**1,055**	1,052	1,0
Total company	**2,394**	2,805	2,7
*Greater Prudhoe Area (Alaska)**	***4***	*4*	

**At year-end 2020 and 2019, the Greater Prudhoe Area in Alaska contained more than 15 percent of our total proved reserves.*

Average Sales Prices		2020	2019	20
Crude Oil Per Barrel				
Consolidated operations				
Alaska*	$	**33.72**	55.85	60.
Lower 48		**35.17**	55.30	62.
United States		**34.48**	55.54	61.
Canada		**23.57**	40.87	48.
Europe		**42.80**	65.12	70.
Asia Pacific		**42.84**	65.02	70.
Africa		**48.64**	64.47	69.
Total international		**42.39**	64.85	70.
Total consolidated operations		**36.69**	58.51	65.
Equity affiliates—Asia Pacific/Middle East		**39.02**	61.32	72.
Total operations		**36.75**	58.57	65.
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**12.13**	16.83	27.
United States		**12.13**	16.85	27.
Canada		**5.41**	19.87	43.
Europe		**23.27**	29.37	36.
Asia Pacific		**33.21**	37.85	47.
Total international		**20.25**	32.29	40.
Total consolidated operations		**12.90**	18.73	29.
Equity affiliates—Asia Pacific/Middle East		**32.69**	36.70	45.
Total operations		**14.61**	20.09	30.
Bitumen Per Barrel				
Consolidated operations—Canada	$	**8.02** **	31.72	22.
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**2.91**	3.19	2.
Lower 48		**1.65**	2.12	2.
United States		**1.66**	2.12	2.
Canada		**1.21**	0.49	1.
Europe		**3.23**	4.92	7.
Asia Pacific*		**5.27**	5.73	5.
Africa		**3.71**	4.87	4.
Total international		**4.31**	5.35	6.
Total consolidated operations		**3.13**	4.19	5.
Equity affiliates—Asia Pacific/Middle East		**3.71**	6.29	6.
Total operations		**3.38**	4.99	5.

**Average sales prices for Alaska crude oil and Asia Pacific 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.*
***Average sales prices include unutilized transportation costs.*

		2020	2019	2
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**14.60**	15.52	14.
Lower 48		**9.93**	9.59	10.
United States		**11.51**	11.52	11.
Canada		**14.29**	16.53	16.
Europe		**8.97**	11.22	11.
Asia Pacific		**9.26**	8.74	9.
Africa		**6.38**	4.46	4.
Total international operations		**10.11**	10.26	10.
Total consolidated		**10.99**	10.99	11.
Equity affiliates—Asia Pacific/Middle East		**4.01**	4.68	4.
Average Production Costs Per Barrel—Bitumen				
Consolidated operations—Canada	$	**12.45**	13.74	13.
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**4.08**	3.87	5.
Lower 48		**1.87**	2.65	2.
United States		**2.62**	3.05	3.
Canada		**0.62**	0.78	0.
Europe		**0.65**	0.48	0.
Asia Pacific		**0.81**	0.76	1.
Africa		**0.91**	0.19	0.
Total international operations		**0.72**	0.60	0.
Total consolidated		**1.91**	2.03	2.
Equity affiliates—Asia Pacific/Middle East		**6.96**	11.46	11.
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**11.59**	8.80	9.
Lower 48		**18.05**	17.03	15.
United States		**15.86**	14.35	13.
Canada		**13.08**	10.00	12.
Europe		**16.24**	12.75	14.
Asia Pacific		**15.66**	16.55	16.
Africa		**2.43**	2.36	2.
Total international operations		**15.01**	12.99	14.
Total consolidated		**15.54**	13.78	13.
Equity affiliates—Asia Pacific/Middle East		**7.89**	8.09	9.

**Includes bitumen.*

Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wel in the years ended December 31, 2020, 2019 and 2018. 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 relatin to oil sands delineation wells located in Canada and CBM test wells located in Asia Pacific/Middle East.

Net Wells Completed

	Productive			Dry	
	2020	2019	2018	**2020**	2019
Exploratory					
Consolidated operations					
Alaska	**-**	7	6	**3**	-
Lower 48	**3**	35	45	**-**	6
United States	**3**	42	51	**3**	6
Canada	**23**	-	2	**-**	-
Europe	**-**	1	*	*****	1
Asia Pacific/Middle East	*****	1	2	*****	1
Africa	**-**	-	-	*****	-
Other areas	**-**	-	-	*****	-
Total consolidated operations	**26**	44	55	**3**	8
Equity affiliates					
Asia Pacific/Middle East	**8**	8	6	**-**	-
Total equity affiliates	**8**	8	6	**-**	-
Development					
Consolidated operations					
Alaska	**7**	12	11	**-**	-
Lower 48	**127**	255	254	**-**	-
United States	**134**	267	265	**-**	-
Canada	**-**	2	1	**-**	-
Europe	**7**	6	9	**-**	-
Asia Pacific/Middle East	**16**	21	12	**-**	-
Africa	**2**	2	1	**-**	-
Other areas	**-**	-	-	**-**	-
Total consolidated operations	**159**	298	288	**-**	-
Equity affiliates					
Asia Pacific/Middle East	**109**	106	75	**-**	-
Total equity affiliates	**109**	106	75	**-**	-

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2020, 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, 2020.

Wells at December 31, 2020

	In Progress		Productive			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Ne
Consolidated operations						
Alaska	5	5	1,576	946	-	
Lower 48	459	240	9,382	4,149	4,182	1,678
United States	464	245	10,958	5,095	4,182	1,678
Canada	24	24	196	103	169	16
Europe	16	3	476	79	59	2
Asia Pacific/Middle East	15	7	337	160	38	18
Africa	7	1	850	139	10	2
Other areas	14	7	-	-	-	
Total consolidated operations	540	287	12,817	5,576	4,458	1,86
Equity affiliates						
Asia Pacific/Middle East	139	32	-	-	4,898	1,15
Total equity affiliates	139	32	-	-	4,898	1,15

Acreage at December 31, 2020

	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	N
Consolidated operations				
Alaska	659	472	1,345	1,33
Lower 48	3,228	1,974	10,215	8,16
United States	3,887	2,446	11,560	9,50
Canada	293	214	3,417	1,94
Europe	430	50	966	36
Asia Pacific/Middle East	921	421	9,015	5,70
Africa	358	58	12,545	2,04
Other areas	-	-	996	54
Total consolidated operations	5,889	3,189	38,499	20,11
Equity affiliates				
Asia Pacific/Middle East	1,026	245	3,820	86
Total equity affiliates	1,026	245	3,820	86

Costs Incurred

Year Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas
	Millions of Dollars							
2020								
Consolidated operations								
Unproved property acquisition	$ 4	10	14	378	-	3	-	9
Proved property acquisition	-	62	62	129	-	-	-	-
	4	72	76	507	-	3	-	9
Exploration	287	116	403	218	110	32	4	38
Development	745	1,758	2,503	102	451	427	18	-
	$ 1,036	1,946	2,982	827	561	462	22	47
Equity affiliates								
Unproved property acquisition	$ -	-	-	-	-	-	-	-
Proved property acquisition	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
Exploration	-	-	-	-	-	12	-	-
Development	-	-	-	-	-	282	-	-
	$ -	-	-	-	-	294	-	-
2019								
Consolidated operations								
Unproved property acquisition	$ 101	45	146	14	-	-	-	197
Proved property acquisition	1	116	117	-	-	115	-	-
	102	161	263	14	-	115	-	197
Exploration	281	390	671	200	119	66	8	39
Development	1,125	3,028	4,153	215	625	486	22	-
	$ 1,508	3,579	5,087	429	744	667	30	236
Equity affiliates								
Unproved property acquisition	$ -	-	-	-	-	62	-	-
Proved property acquisition	-	-	-	-	-	-	-	-
	-	-	-	-	-	62	-	-
Exploration	-	-	-	-	-	23	-	-
Development	-	-	-	-	-	171	-	-
	$ -	-	-	-	-	256	-	-
2018								
Consolidated operations								
Unproved property acquisition	$ 119	126	245	126	-	-	-	-
Proved property acquisition	2,227	16	2,243	6	-	-	-	-
	2,346	142	2,488	132	-	-	-	-
Exploration	203	500	703	90	65	82	(6)	41
Development	718	2,715	3,433	301	703	773	16	-
	$ 3,267	3,357	6,624	523	768	855	10	41
Equity affiliates								
Unproved property acquisition	$ -	-	-	-	-	-	-	-
Proved property acquisition	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
Exploration	-	-	-	-	-	22	-	-
Development	-	-	-	-	-	206	-	-
	$ -	-	-	-	-	228	-	-

Capitalized Costs

At December 31		Millions of Dollars						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/Middle East	Africa	Other Areas
2020								
Consolidated operations								
Proved property	$ 21,819	37,452	59,271	7,255	14,931	11,913	942	-
Unproved property	1,398	631	2,029	1,529	151	89	114	229
	23,217	38,083	61,300	8,784	15,082	12,002	1,056	229
Accumulated depreciation, depletion and amortization	11,098	27,948	39,046	2,431	10,015	8,567	387	9
	$ 12,119	10,135	22,254	6,353	5,067	3,435	669	220
Equity affiliates								
Proved property	$ -	-	-	-	-	10,310	-	-
Unproved property	-	-	-	-	-	2,187	-	-
	-	-	-	-	-	12,497	-	-
Accumulated depreciation, depletion and amortization	-	-	-	-	-	6,959	-	-
	$ -	-	-	-	-	5,538	-	-
2019								
Consolidated operations								
Proved property	$ 20,957	37,491	58,448	6,673	14,113	14,566	924	-
Unproved property	1,429	1,055	2,484	1,149	87	501	123	290
	22,386	38,546	60,932	7,822	14,200	15,067	1,047	290
Accumulated depreciation, depletion and amortization	9,419	26,294	35,713	2,050	9,017	10,253	379	9
	$ 12,967	12,252	25,219	5,772	5,183	4,814	668	281
Equity affiliates								
Proved property	$ -	-	-	-	-	9,996	-	-
Unproved property	-	-	-	-	-	2,223	-	-
	-	-	-	-	-	12,219	-	-
Accumulated depreciation, depletion and amortization	-	-	-	-	-	6,390	-	-
	$ -	-	-	-	-	5,829	-	-

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantit

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end ec conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time a becomes available. Probable or possible reserves, which may become proved in the future, were not considered. Th calculations also require assumptions as to the timing of future production of proved reserves and the timing and amo future development costs, including dismantlement, and future production costs, including taxes other than income ta

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas prop 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
2020							
Consolidated operations							
Future cash inflows	$ 30,145	31,533	61,678	4,198	9,857	7,940	9,997
Less:							
Future production costs	22,905	17,582	40,487	4,316	4,770	3,838	1,277
Future development costs	7,932	12,799	20,731	750	3,688	1,289	461
Future income tax provisions	-	376	376	-	267	1,075	7,571
Future net cash flows	(692)	776	84	(868)	1,132	1,738	688
10 percent annual discount	(1,501)	(820)	(2,321)	(396)	117	406	294
Discounted future net cash flows	$ 809	1,596	2,405	(472)	1,015	1,332	394
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	17,284	-
Less:							
Future production costs	-	-	-	-	-	10,239	-
Future development costs	-	-	-	-	-	1,186	-
Future income tax provisions	-	-	-	-	-	1,728	-
Future net cash flows	-	-	-	-	-	4,131	-
10 percent annual discount	-	-	-	-	-	1,269	-
Discounted future net cash flows	$ -	-	-	-	-	2,862	-
Total company							
Discounted future net cash flows	$ 809	1,596	2,405	(472)	1,015	4,194	394

*Undiscounted future net cash flows related to the proved oil and gas reserves disclosed for Canada for the year ending December are negative due to the inclusion of asset retirement costs and certain indirect costs in the calculation of the standardized measure discounted future net cash flows. These costs are not required to be included in the economic limit test for proved developed reser defined in Regulation S-X Rule 4-10. Future net cash flows for Canada were also impacted by lower 12-month average pricing fo and crude oil in 2020. Commodity prices have since improved in the current environment.

				Millions of Dollars			
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afri
2019							
Consolidated operations							
Future cash inflows	$ 70,341	53,400	123,741	8,244	16,919	13,084	15,58
Less:							
Future production costs	40,464	22,194	62,658	4,525	5,843	5,162	1,31
Future development costs	9,721	14,083	23,804	577	4,143	2,179	48
Future income tax provisions	3,904	2,793	6,697	-	4,201	1,931	12,74
Future net cash flows	16,252	14,330	30,582	3,142	2,732	3,812	1,03
10 percent annual discount	6,571	4,311	10,882	1,198	558	835	46
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	2,977	57
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	31,671	
Less:							
Future production costs	-	-	-	-	-	16,157	
Future development costs	-	-	-	-	-	1,218	
Future income tax provisions	-	-	-	-	-	3,086	
Future net cash flows	-	-	-	-	-	11,210	
10 percent annual discount	-	-	-	-	-	4,040	
Discounted future net cash flows	$ -	-	-	-	-	7,170	
Total company							
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	10,147	57

				Millions of Dollars			
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa
2018							
Consolidated operations							
Future cash inflows	$ 82,072	56,922	138,994	6,039	26,989	16,368	16,434
Less:							
Future production costs	42,755	21,363	64,118	4,099	8,567	5,705	1,336
Future development costs	10,053	12,136	22,189	606	7,608	1,995	507
Future income tax provisions	5,538	4,418	9,956	-	7,102	2,873	13,492
Future net cash flows	23,726	19,005	42,731	1,334	3,712	5,795	1,099
10 percent annual discount	10,349	6,461	16,810	426	371	1,132	498
Discounted future net cash flows	$ 13,377	12,544	25,921	908	3,341	4,663	601
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	33,606	-
Less:							
Future production costs	-	-	-	-	-	16,449	-
Future development costs	-	-	-	-	-	1,228	-
Future income tax provisions	-	-	-	-	-	3,147	-
Future net cash flows	-	-	-	-	-	12,782	-
10 percent annual discount	-	-	-	-	-	4,853	-
Discounted future net cash flows	$ -	-	-	-	-	7,929	-
Total company							
Discounted future net cash flows	$ 13,377	12,544	25,921	908	3,341	12,592	601

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars							
	Consolidated Operations			Equity Affiliates			Total Company	
	2020	2019	2018	**2020**	2019	2018	**2020**	2019
Discounted future net cash flows at the beginning of the year	$ **27,372**	35,434	20,609	**7,170**	7,929	4,395	**34,542**	43,363
Changes during the year								
Revenues less production costs for the year	**(5,198)**	(13,424)	(14,909)	**(897)**	(1,673)	(1,651)	**(6,095)**	(15,097)
Net change in prices and production costs	**(34,307)**	(13,538)	25,391	**(4,769)**	(422)	4,559	**(39,076)**	(13,960)
Extensions, discoveries and improved recovery, less estimated future costs	**887**	2,985	4,574	**22**	260	382	**909**	3,245
Development costs for the year	**3,593**	5,333	5,197	**192**	239	271	**3,785**	5,572
Changes in estimated future development costs	**754**	559	(1,141)	**(205)**	(21)	14	**549**	538
Purchases of reserves in place, less estimated future costs	**1**	10	3,033	**(3)**	-	-	**(2)**	10
Sales of reserves in place, less estimated future costs	**(302)**	(1,997)	(1,531)	**-**	-	-	**(302)**	(1,997)
Revisions of previous quantity estimates	**(2,299)**	2,099	(365)	**(42)**	69	62	**(2,341)**	2,168
Accretion of discount	**3,984**	5,144	3,055	**804**	869	485	**4,788**	6,013
Net change in income taxes	**10,189**	4,767	(8,479)	**590**	(80)	(588)	**10,779**	4,687
Total changes	**(22,698)**	(8,062)	14,825	**(4,308)**	(759)	3,534	**(27,006)**	(8,821)
Discounted future net cash flows at year end	$ **4,674**	27,372	35,434	**2,862**	7,170	7,929	**7,536**	34,542

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by 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 calculate production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales pr future estimated costs, discounted at 10 percent.

- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted 10 percent.

- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production development costs.

- The net change in income taxes is the annual change in the discounted future income tax provisions.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AN 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 Commissi 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 requi disclosure. As of December 31, 2020, 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 th evaluation, our Chairman and Chief Executive Officer and our Executive Vice President and Chief Financia Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 202

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of t 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 81 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 85 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 33.

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 o 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 o 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 th "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 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, 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 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, 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 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, 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 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, 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 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, 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 appeari in our 2021 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 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 80, are filed as part of this annual report.

2. Financial Statement Schedules

All financial statement 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 182 through 190, are filed as pa of this annual report.

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 among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Cana 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).
2.4	Agreement and Plan of Merger, dated as of October 18, 2020, among ConocoPhillips, Falcon Merger Sub Corp. and Concho Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 19, 2020; File No. 001-32395).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to th 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 fi 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, 20 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K fi 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 a 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 (incorporated by reference to Exhibit 4.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).

10.1	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to th 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 th Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.3	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference 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 Exhib 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).
10.7	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, 20 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 end December 31, 2005; File No. 001-32395).
10.9	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference 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 (incorporate by reference to Exhibit 10.10.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).
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- 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 (incorporated by reference to Exhibit 10.11.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).
10.11.2	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated January 1, 2020 (incorporated by reference to Exhibit 10.11.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).
10.12	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhi 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 20 File No. 000-49987).

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 end 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 t 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 Repor 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 Repor 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 10.19.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).

10.19.2	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated January 1, 2020 (incorporated by reference to Exhibit 10.19.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).
10.20	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Pla 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 Annu 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 referen 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 end 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 Forn 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 referen 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 referen 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 1(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 1(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, date 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. to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 201 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 Progra 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 Quarte 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 Sha Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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).
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 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; F No. 001-32395).
10.25.18	Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as par of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by referen 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).

10.26.1	2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by referen 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 3(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- 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 For 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 Optior Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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 referen 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 Progr 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 Sto Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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 t the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File N 001-32395).
10.26.12	Form of Key Employee Award Terms and Conditions for eligible employees on the Canada payro 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 1 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 Sto
Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhilli
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 U
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 1
K for the year ended December 31, 2017; File No. 001-32395).

10.26.15 Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Sto
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 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; 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, 201
File No. 001-32395).

10.29 Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benef
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 Exhi
10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 20
File No. 001-32395).

10.30.1 Successor Trustee Agreement of the Deferred Compensation Trust Agreement for Non-Employee
Directors of ConocoPhillips dated July 31, 2020 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2020; File
No. 001-32395).

10.30.2 First Amendment to the Successor Trust Agreement of the Deferred Compensation Trust Agreeme
for Non-Employee Directors of ConocoPhillips, dated August 4, 2020 (incorporated by reference
Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2020; 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
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 (incorpora 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. to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 201 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).
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 Exhibi 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 3(2019; File No. 001-32395).
10.41	ConocoPhillips Executive Restricted Stock Unit Program, dated February 11, 2020 (incorporated reference to Exhibit 10.1 to the Quarter Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2020; File No. 001-32395).
10.42	Letter agreement with Don E. Wallette, Jr. dated August 3, 2020 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 2020; File No. 001-32395).
21*	List of Subsidiaries of ConocoPhillips.
22*	Subsidiary Guarantors of Guaranteed Securities
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 Exchang 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 ha duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONOCOPHILLIPS

February 16, 2021	*/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 16, 2021, 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/ William L. Bullock, Jr. William L. Bullock, 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/ Timothy A. Leach Timothy A. Leach	Director
/s/ William H. McRaven William H. McRaven	Director
/s/ Sharmila Mulligan Sharmila Mulligan	Director
/s/ Eric D. Mullins Eric D. Mullins	Director
/s/ Arjun N. Murti Arjun N. Murti	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ David T. Seaton David T. Seaton	Director
/s/ R.A. Walker R.A. Walker	Director

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 register**
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 A
[x] Yes [

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) o Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant wa required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. [x] Yes [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit such files). [x] Yes [

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated fil 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

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 Secti 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

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 d 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 th
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 obligatio
ASC	accounting standards codi
ASU	accounting standards upd
DD&A	depreciation, depletion an amortization
FASB	Financial Accounting Sta Board
FIFO	first-in, first-out
G&A	general and administrativ
GAAP	generally accepted accou principles
LIFO	last-in, first-out
NPNS	normal purchase normal s
PP&E	properties, plants and equ
SAB	staff accounting bulletin
VIE	variable interest entity

Miscellaneous

EPA	Environmental Protection
EU	European Union
FERC	Federal Energy Regulator Commission
GHG	greenhouse gas
HSE	health, safety and environ
ICC	International Chamber of Commerce
ICSID	World Bank's Internation Centre for Settlement of Investment Disputes
IRS	Internal Revenue Service
OTC	over-the-counter
NYSE	New York Stock Exchang
SEC	U.S. Securities and Excha 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 t 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 t 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 corre 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 disclosur 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, Tex 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 worldwi 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 Operation
disclosures following the Notes to Consolidated Financial Statements. Approximately 80 percent of 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 summa reserves table.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2019**	2018	20
Crude oil			
Consolidated operations	**2,562**	2,533	2,3
Equity affiliates	**73**	78	
Total Crude Oil	**2,635**	2,611	2,4
Natural gas liquids			
Consolidated operations	**361**	349	3
Equity affiliates	**39**	42	
Total Natural Gas Liquids	**400**	391	3
Natural gas			
Consolidated operations	**1,209**	1,265	1,2
Equity affiliates	**736**	760	7
Total Natural Gas	**1,945**	2,025	1,9
Bitumen			
Consolidated operations	**282**	236	2
Total Bitumen	**282**	236	2
Total consolidated operations	**4,414**	4,383	4,1
Total equity affiliates	**848**	880	8
Total company	**5,262**	5,263	5,0

Total production of 1,348 MBOED increased 5 percent in 2019 compared with 2018. The increase in 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 Decemb 2018. The increase in production was partly offset by normal field decline and disposition impacts, primaril 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 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 compare with $53.88 per BOE in 2018, reflecting weaker marker prices as a result of macroeconomic demand concer Our worldwide annual average crude oil price decreased 10 percent, from $68.13 per barrel in 2018 to $60.9 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 NGL We are the largest crude oil producer in Alaska and have major ownership interests in two of North America 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 a year-end 2019. Alaska operations contributed 25 percent of our worldwide liquids production and less than percent of our natural gas production.

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

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Poi 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 recove 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 Petroleu Reserve-Alaska (NPR-A). In 2019, we continued drilling additional wells using the available well slots on t pad.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPR-A, was formed in 2008. I 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 i 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 potentia 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 progres 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 approximat 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 Ju 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 20 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 CI 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 U 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 wer 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 Slop

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 offshor acres, with a portfolio of conventional production from legacy assets as well as newer production from our l cost of supply, shorter cycle time, resource-rich unconventional plays. Based on 2019 production volumes, 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	To MBO
Average Daily Net Production					
Eagle Ford	Various %	Various	174	251	2
Gulf of Mexico	Various	Various	15	11	
Gulf Coast—Other	Various	Various	3	9	
Total Gulf Coast			192	271	2
Bakken	Various	Various	82	92	
Permian Unconventional	Various	Various	40	94	
Permian Conventional	Various	Various	20	59	
Anadarko Basin	Various	Various	5	58	
Wyoming/Uinta	Various	Various	-	36	
Niobrara*	Various	Various	8	12	
Total Great Plains			155	351	2
Total Lower 48			347	622	4

**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 tota 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 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 63 operated wells drilled during the year and 44 operated wells brought online. Production increased 1 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 Cany 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 th 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 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 segmen
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facilit 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 Sugarloa Condensate Processing Facility, a 30 MBD condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processin 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-ric
Montney unconventional play in British Columbia. In 2019, operations in Canada contributed 7 percent of o
worldwide liquids production and less than 1 percent of our natural gas production.

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

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 ar 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. Surmon is a 50/50 joint venture with Total S.A. The second phase of the Surmont Project achieved first production i 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 201 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 se 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 we 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 Islan

EUROPE AND NORTH AFRICA

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

Norway

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production					
Greater Ekofisk Area	35.1%	ConocoPhillips	50	44	
Heidrun	24.0	Equinor	14	29	
Alvheim	20.0	Aker BP	10	12	
Visund	9.1	Equinor	4	46	
Aasta Hansteen	10.0	Equinor	-	64	
Troll	1.6	Equinor	2	49	
Other	Various	Equinor	8	10	
Total Norway			88	254	1

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, Englar 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 ar exported via shuttle tankers. Part of the natural gas is currently injected into the reservoir for optimization o crude oil production, some gas is transported for use as feedstock in a methanol plant in Norway, in which w own an 18 percent interest, and the remainder is transported to Europe via gas processing terminals in Norw

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 fo 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 Se

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 from Ekofisk to a crude oil stabilization and NGLs processing facility in Teesside, England.

United Kingdom

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

**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 so was 50 MBOED in 2019. For additional information on this transaction, see Note 5—Asset Acquisitions an 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 owners interest, to support our Norway operations.

Libya

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

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 o the last several years due to the shutdown of the Es Sider crude oil export terminal. In 2019, we had 19 cruc 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 t 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 natural gas production.

Australia and Timor-Leste

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	To MBO
Average Daily Net Production					
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	679	1
Bayu-Undan*	56.9	ConocoPhillips	10	194	
Athena/Perseus*	50.0	ExxonMobil	-	31	
Total Australia and Timor-Leste			10	904	1

**This asset is held-for-sale as of December 31, 2019. See Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financia 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 financ 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 betwe 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 pipeli 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 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 project will be finalized, gas and condensate sales agreements progressed, and access arrangements negotiate 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 operatorsh 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 the government of Timor-Leste.

In October 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets an 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	To MBO
Average Daily Net Production					
South Sumatra	54 %	ConocoPhillips	2	321	
Total Indonesia			2	321	

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 i 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 yea after 2023 and retain a participating interest until 2043.

Production from the South Jambi "B" PSC has reached depletion and field development has been suspendec 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	To MBO
Average Daily Net Production					
Penglai	49.0 %	CNOOC	29	-	
Panyu	24.5	CNOOC	6	-	
Total China			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 development.

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

The Penglai 19-3/19-9 Phase 3 Project consists of three new wellhead platforms and a central process platform. First oil from Phase 3 was achieved in 2018 for two of the platforms, with the third platform plan to come online in the second quarter of 2020. This project could include up to 186 wells, 42 of which ha 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 i 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	To MBOE
Average Daily Net Production					
Gumusut	29.0 %	Shell	23	-	2
Kebabangan (KBB)	30.0	KPOC	3	91	1
Malikai	35.0	Shell	15	-	1
Siakap North-Petai	21.0	PTTEP	1	-	
Total Malaysia			42	91	5

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 stat 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 fro a permanent, semi-submersible Floating Production System was achieved in 2014. We currently have a 30 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 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 vi 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. 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. 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	To MBO
Average Daily Net Production					
QG3	30.0 %	Qatargas Operating Company Limited	21	373	
Total Qatar			21	373	

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 facilitie which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field ov a 25-year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LN 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 an 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 acre 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 Austr 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 Vac 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 indic 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 syste meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containme 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 organizatio based in Stavanger, Norway, which was created to enhance the industry's capability to respond to internatio 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 a subsea well incident. This complements the work being undertaken in the U.S. by MWCC and provides w 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 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. North America, our primary OSROs include the Marine Spill Response Corporation for the continental Unit States and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prin William Sound, respectively. Internationally, we maintain memberships in various regional OSROs includi 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, produc 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 reserv for year-end 2018 and year-end 2017, which are shown in this filing, and estimates of these reserves shown i 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 th 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 singl 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-effectiv 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 the worldwid 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 processe 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 goa 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 tracke 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 cost 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 n 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 we 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 contro

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 t 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 redu 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 i Note 9—Impairments and the "APLNG" section of Note 6—Investments, Loans and Long-Term Receivable 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 propertie
- 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 p 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 shar
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 o shares during any period, and our decision to commence, discontinue or resume repurchases in any period w depend on the same factors that our Board of Directors may consider when declaring dividends, among othe

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 comm 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 fo funding. There can be no assurance that additional debt or equity financing will be available in the future or 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 ab to do so. Our ability to obtain additional financing, or refinance our existing indebtedness when it matures o in accordance with our plans, will be subject to a number of factors, including market conditions, our operat 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 downgrad 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 i 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 liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry 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 counterparti 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 resul 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 a arbitration award issued by the International Chamber of Commerce (ICC) Tribunal in favor of ConocoPhill on a contractual dispute arising from Venezuela's expropriation of our interests in the Petrozuata and Hama 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 amou 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 conduc successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline material as we produce crude oil, bitumen, natural gas and NGLs, and our business will experience reduced cash flow 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, natur 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 prope 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, whic 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 emission
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardo 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, c 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, othe 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 o 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 ar 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. joine 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 ar 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 f 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 inc 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 aff 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 the 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 th 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 material 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 competitive 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 permeabili rock formations. A range of local, state, federal and national laws and regulations currently govern or, in so 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 productio and development of oil and natural gas in areas where we conduct operations, we may incur significant costs 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, limitatio or prohibitions could have a material adverse effect on our business, prospects, results of operations, financi 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 asse by the Venezuelan government, have affected operations significantly in the past and may continue to do so 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 governmen 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 local government authorities, such as expropriations.

Our business may be adversely affected by price controls, government-imposed limitations on production 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, bitume 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 crude oil, bitumen, natural gas and NGL wells below actual production capacity. Because legal requirement 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 an pipeline facilities and equipment, as well as any necessary diluents to prepare our crude oil, bitumen, natura 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 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 fro 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 w 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 obligation 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 o 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 n 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 Energ Consideration for the transaction included 208 million Cenovus Energy common shares. We may not be 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 operation 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 t 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 equipmen 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 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 colle 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 parti with whom we do business and attempted cyber terrorism.

In addition, computers control oil and gas production, processing equipment and distribution systems global 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 o 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 contro 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 an 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 counterpa 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, o 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 o 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 ar 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 Commissi 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 an paying an administrative penalty of $120,014.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Name	Position Held	A
Catherine A. Brooks	Vice President and Controller	5
William L. Bullock, Jr.	President, Asia Pacific & Middle East	5
Ellen R. DeSanctis	Senior Vice President, Corporate Relations	6
Matt J. Fox	Executive Vice President and Chief Operating Officer	5
Michael D. Hatfield	President, Alaska, Canada and Europe	5
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	5
Andrew D. Lundquist	Senior Vice President, Government Affairs	5
Dominic E. Macklon	President, Lower 48	5
Kelly B. Rose	Senior Vice President, Legal, General Counsel and Corporate Secretary	5
Don E. Wallette, Jr.	Executive Vice President and Chief Financial Officer	6

**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 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 20 and Executive Vice President, Exploration and Production, from 2012 to 2016. Prior to that, he was employ 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, Healt 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 201 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 Vi
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, 201
having previously served as Executive Vice President, Finance, Commercial and Chief Financial Officer sin
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	20
First	$ **0.305**	0.2
Second	**0.305**	0.2
Third	**0.305**	0.2
Fourth	**0.420**	0.3

Number of Stockholders of Record at January 31, 2020*	41,8

**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 indebtedne 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 divide 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 divider 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 divider 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 Doll Approximate Dol Value of Sha that May Yet Purchased Under Plans or Progra
October 1-31, 2019	4,844,970	$	55.54	4,844,970	$	5,8
November 1-30, 2019	4,020,276		58.20	4,020,276		5,62
December 1-31, 2019	3,943,490		62.31	3,943,490		5,3
	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 pl*

In late 2016, we initiated our current share repurchase program. As of December 31, 2019, we had announc 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 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 stoc 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 fisca 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 respectiv 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 b Occidental completed in 2019, Anadarko's performance has been excluded from all five years of the Prior P 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.

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**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	20
Sales and other operating revenues	$	**32,567**	36,417	29,106	23,693	29,5
Net income (loss)		**7,257**	6,305	(793)	(3,559)	(4,3
Net income (loss) attributable to ConocoPhillips		**7,189**	6,257	(855)	(3,615)	(4,4
Per common share						
Basic		**6.43**	5.36	(0.70)	(2.91)	(3.
Diluted		**6.40**	5.32	(0.70)	(2.91)	(3.
Total assets		**70,514**	69,980	73,362	89,772	97,4
Long-term debt		**14,790**	14,856	17,128	26,186	23,4
Cash dividends declared per common share		**1.34**	1.16	1.06	1.00	2.

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 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 contain 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 o 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,” “targ 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 securitie 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 (lo 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, Tex 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 supertank 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, a 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. Bren 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, deli 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 deb a level we believe is sufficient to maintain a strong investment grade credit rating through price cycles; alloc 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 our value proposition, as evidenced by the results discussed below, positions us for success in an environme 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 provide 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 end 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 sha 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 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 i 2019 and 47 MBOED in 2018, is used to measure our ability to grow production organically. Our underlyin 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

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 t 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 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 ou Asia Pacific and Middle East
segment.

In October 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets an 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 i 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. Result 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 $38 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. 2019, production from Niobrara was 11 MBOED. Year-end 2019 reserves associated with the Niobrara ass to be sold were 14 MMBOE. This transaction is subject to regulatory approval and other conditions preced and is expected to close in the first quarter of 2020. The Niobrara results of operations are reported within o Lower 48 segment.

For more information regarding the accounting impacts of these transactions, see Note 5—Asset Acquisitio 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 volatili 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.

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

- <u>Maintain a relentless focus on safety and environmental stewardship</u>. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we ar 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 grow Demonstrating our commitment to sustainability and environmental stewardship, on November 201 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 anoth 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 advocacy branch of the CLC. In early 2019, we issued our first stand-alone Climate-related Ris 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 ma 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 bas 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 a 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 expectec 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 compromis 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 absolut 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 certa non-core assets, including the U.K., Australia-West and our Niobrara assets in the Lower 4 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 wit 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 deli on our priorities through the price cycles. Our priorities include execution of our development plan 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 comm 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 activitie Since we initiated our current share repurchase program in late 2016, we have repurchased $9.6 bill of shares. Additionally, as of December 31, 2019, $5.4 billion of repurchase authority remained of $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 $1 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 condition and other factors. See Risk Factors "Our ability to declare and pay dividends and repurchase shares 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 an decrease as prices decline. Reserve replacement represents the net change in proved reserves, net o 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 fro 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 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 billi BOE related to sales and purchases, was 40 percent, reflecting development activities as well as low prices during that period.

  Historically, our reserve replacement has varied considerably year to year contingent upon the timin of major projects which may have long lead times between capital investment and production. In th last several years, more of our capital has been allocated to short cycle time, onshore, unconvention 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 acce to high-potential areas due to environmental or other regulation may negatively impact our ability t increase our reserve base. As such, the timing and level at which we add to our reserve base may, o 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 conve additional resources to reserves, achieve greater operating efficiencies and reduce our environmenta 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 expertis 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 OPE 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:

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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 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 $2.6 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 deman growth.

Our realized bitumen price increased 42 percent from $22.29 per barrel in 2018 to $31.72 per barrel 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 on 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 opportunitie 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 unconventional fields. Should one or more of these events occur, our revenues would be reduced, a 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 tim our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-dov 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 impairmen charges to long-lived assets used in operations, investments in nonconsolidated entities accounted fo 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 or 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, regulato 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 managemen carefully considers the fiscal and regulatory environment when evaluating projects or determining t 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 rec third-party pipeline outage on the Kebabangan Field in Malaysia. First-quarter 2020 production is expected 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 regio 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 interes expense, premiums incurred on the early retirement of debt, corporate overhead, certain technology activitie 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 productior

RESULTS OF OPERATIONS

This section of the Form 10-K discusses year-to-year comparisons between 2019 and 2018. For discussion year-to-year comparisons between 2018 and 2017, see "Management's Discussion and Analysis of Financia 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	20
Alaska	$	**1,520**	1,814	1,4
Lower 48		**436**	1,747	(2,3
Canada		**279**	63	2,5
Europe and North Africa		**2,724**	1,866	5
Asia Pacific and Middle East		**1,929**	2,070	(1,0
Other International		**263**	364	1
Corporate and Other		**38**	(1,667)	(2,1
Net income (loss) attributable to ConocoPhillips	$	**7,189**	6,257	(8

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 201 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 quarte 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 Malaysi 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 ou 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 meth 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 segme 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 associat 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 i 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-t 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 Consolidated Financial Statements.

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

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 activit 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 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 c income tax provision (benefit) and effective tax rate.

Summary Operating Statistics

		2019	2018	20
Average Net Production				
Crude oil (MBD)		**705**	653	5
Natural gas liquids (MBD)		**115**	102	1
Bitumen (MBD)		**60**	66	1
Natural gas (MMCFD)		**2,805**	2,774	3,2
Total Production (MBOED)		**1,348**	1,283	1,3
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per bbl)	**$**	**60.99**	68.13	51.
Natural gas liquids (per bbl)		**20.09**	30.48	25.
Bitumen (per bbl)		**31.72**	22.29	22.
Natural gas (per mcf)		**5.03**	5.65	4.
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical, lease rental, and other	**$**	**322**	274	3
Leasehold impairment		**221**	56	1
Dry holes		**200**	39	4
	$	**743**	369	9

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwi 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 Alasl following acquisitions closed in 2018.
- Higher production in Norway due to drilling activity and the startup of Aasta Hansteen in Decembe 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 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 201 from 1,195 MBOED in 2018.

Alaska

		2019	2018	20
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**1,520**	1,814	1,4
Average Net Production				
Crude oil (MBD)		**202**	171	1
Natural gas liquids (MBD)		**15**	14	
Natural gas (MMCFD)		**7**	6	
Total Production (MBOED)		**218**	186	1
Average Sales Prices				
Crude oil (per bbl)	$	**64.12**	70.86	53.
Natural gas (per mcf)		**3.19**	2.48	2.

The Alaska segment primarily explores for, produces, transports and markets crude oil, NGLs and natural ga 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 a 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 rul 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 GK and WNS in 2018, which provided an incremental 38 MBOED of production in 2019, as well as volumes fro 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	20
Net Income (Loss) Attributable to ConocoPhillips				
(millions of dollars)	$	**436**	1,747	(2,3
Average Net Production				
Crude oil (MBD)		**266**	229	1
Natural gas liquids (MBD)		**81**	69	
Natural gas (MMCFD)		**622**	596	8
Total Production (MBOED)		**451**	397	3
Average Sales Prices				
Crude oil (per bbl)	$	**55.30**	62.99	47.
Natural gas liquids (per bbl)		**16.83**	27.30	22.
Natural gas (per mcf)		**2.12**	2.82	2.

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf of Mexico. Durin 2019, the Lower 48 contributed 39 percent of our worldwide liquids production and 22 percent of our natura 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 exploratio 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 LNC 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 th 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 201

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 earning of affiliates" line on our consolidated income statement. We completed the sale in the second quarter of 201 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 afte 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 $38[illegible] 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 Lowe 48 segment for $186 million, plus customary adjustments. The assets met the held for sale criteria in Januar 2020 and the transaction is expected to be completed in the first quarter of 2020. No gain or loss is anticipat 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	20
Net Income Attributable to ConocoPhillips				
(millions of dollars)	$	**279**	63	2,5
Average Net Production				
Crude oil (MBD)		**1**	1	
Natural gas liquids (MBD)		**-**	1	
Bitumen (MBD)				
Consolidated operations		**60**	66	
Equity affiliates		**-**	-	
Total bitumen		**60**	66	1
Natural gas (MMCFD)		**9**	12	1
Total Production (MBOED)		**63**	70	1
Average Sales Prices				
Crude oil (per bbl)	$	**40.87**	48.73	43.
Natural gas liquids (per bbl)		**19.87**	43.70	21.
Bitumen (dollars per bbl)*				
Consolidated operations		**31.72**	22.29	21.
Equity affiliates		**-**	-	23.
Total bitumen		**31.72**	22.29	22.
Natural gas (per mcf)		**0.49**	1.00	1.

**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 fro 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 earnin 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 milli 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 t 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 fi 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 barr 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	20
Net Income Attributable to ConocoPhillips				
(millions of dollars)	$	**2,724**	1,866	5
Average Net Production				
Crude oil (MBD)		**138**	149	1
Natural gas liquids (MBD)		**7**	8	
Natural gas (MMCFD)		**478**	503	4
Total Production (MBOED)		**224**	241	2
Average Sales Prices				
Crude oil (dollars per bbl)	$	**64.94**	70.71	54.
Natural gas liquids (per bbl)		**29.37**	36.87	34.
Natural gas (per mcf)		**4.92**	7.65	5.

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 compare 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 wh these assets became held-for-sale. Partly offsetting the increase in earnings were the absence of a $774 milli 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	20
Net Income (Loss) Attributable to ConocoPhillips				
(millions of dollars)	$	**1,929**	2,070	(1,0
Average Net Production				
Crude oil (MBD)				
Consolidated operations		**85**	89	
Equity affiliates		**13**	14	
Total crude oil		**98**	103	1
Natural gas liquids (MBD)				
Consolidated operations		**4**	3	
Equity affiliates		**8**	7	
Total natural gas liquids		**12**	10	
Natural gas (MMCFD)				
Consolidated operations		**637**	626	6
Equity affiliates		**1,052**	1,031	1,0
Total natural gas		**1,689**	1,657	1,6
Total Production (MBOED)		**392**	389	4
Average Sales Prices				
Crude oil (dollars per bbl)				
Consolidated operations	$	**65.02**	70.93	54.
Equity affiliates		**61.32**	72.49	54.
Total crude oil		**64.52**	71.14	54.
Natural gas liquids (dollars per bbl)				
Consolidated operations		**37.85**	47.20	41.
Equity affiliates		**36.70**	45.69	38.
Total natural gas liquids		**37.10**	46.13	39.
Natural gas (dollars per mcf)				
Consolidated operations		**5.91**	6.15	4.
Equity affiliates		**6.29**	6.06	4.
Total natural gas		**6.15**	6.09	4.

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; low 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 decreas 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 a
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 Updates

In the second quarter of 2019, we recognized an after-tax gain of $52 million upon completion of the sale of 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 an operations to Santos for $1.39 billion, plus customary adjustments, with an effective date of January 1, 2019 addition, we will receive a payment of $75 million upon final investment decision of the Barossa developme 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 complete 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-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	20
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**263**	364	16

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 forc 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 Austra Basin in southern Argentina. In 2019, we acquired and processed 3-D seismic covering 500 square miles, w evaluation of the data ongoing.

In November 2019, we acquired interests in two nonoperated blocks in the Neuquén Basin targeting the Vac 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	20
Net Income (Loss) Attributable to ConocoPhillips				
Net interest	$	**(604)**	(680)	(7
Corporate general and administrative expenses		**(252)**	(91)	(1
Technology		**123**	109	
Other		**771**	(1,005)	(1,2
	$	**38**	(1,667)	(2,1

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 benefi 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, ar 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 finalizatior of rules related to the 2017 Tax Cuts and Jobs Act. See Note 19—Income Taxes, in the Notes to Consolidat 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	
Net cash provided by operating activities	$	**11,104**	12,934	7,
Cash and cash equivalents		**5,088**	5,915	6.
Short-term debt		**105**	112	2.
Total debt		**14,895**	14,968	19,
Total equity		**35,050**	32,064	30.
Percent of total debt to capital*		**30 %**	32	
Percent of floating-rate debt to total debt		**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 o 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 funds as described below in the "Significant Changes in Capital" section, will be sufficient to meet our fundi 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 protec 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 ter 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. T decrease was primarily due to lower prices, lower collections related to settlements reached with Ecuador an PDVSA, and a pension contribution made in conjunction with the sale of two U.K. subsidiaries, partially off 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, LN 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-effect 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 10 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 201 Approximately 51 percent of organic reserve additions are from Lower 48, 13 percent from Alaska, 12 perce 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 billio BOE from sales and purchases, was negative 34 percent, reflecting the impact of asset dispositions and lowe 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 maj projects which may have long lead times between capital investment and production. In the last several yea 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 o asset dispositions during that period. Our organic reserve replacement during the three years ended Decemb 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 ou 2020 capital budget, see the "2020 Capital Budget" section within "Capital Resources and Liquidity" and fo 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 i 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 continger payments from Cenovus Energy.

In the fourth quarter of 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-W 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 ma 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 equit securities.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter int 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, w 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 o $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 divider 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 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 2020. In February 2020, we announced that the Board of Directors approved an increase to our authorizatio 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, 20

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

(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 th 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 busines 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 operat

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for th years 2020 through 2024. For additional information related to expected benefit payments subsequen 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 fo 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 a 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	20
Alaska	$	**1,513**	1,298	8
Lower 48		**3,394**	3,184	2,1
Canada		**368**	477	2
Europe and North Africa		**708**	877	8
Asia Pacific and Middle East		**584**	718	4
Other International		**8**	6	
Corporate and Other		**61**	190	
Capital Program	$	**6,636**	6,750	4,5

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 Operation 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 placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various acti 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 contingen liability exposures will exceed current accruals by an amount that would have a material adverse impact on o consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statemen

Legal and Tax Matters
We are subject to various lawsuits and claims including but not limited to matters involving oil and gas roya 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 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 t 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 regulatio as other companies in our industry. The most significant of these environmental laws and regulations includ 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 Superfund), which imposes liability on generators, transporters and arrangers of hazardous substanc 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, stora 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 discharg 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 respon 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 o hazardous substances and hazardous wastes. They also, in most cases, require permits in association with ne or modified operations. These permits can require an applicant to collect substantial information in connecti 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 law 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 o 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 restriction 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 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 the 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 part 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 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 att 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 financia condition.

Expensed environmental costs were $511 million in 2019 and are expected to be about $545 million per yea 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 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 curre 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 uniq 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 o 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 futu 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 material impact on our results of operations and financial condition. Examples of legislation or precursors f 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 wit emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or equivalent, per year t meet an industry benchmark intensity. The total cost of these regulations in 2019 was approximatel $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 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 legislatio 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 Unite 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 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 leve with respect to GHG emissions. Such regulation could take any of several forms that may result in the creat of additional costs in the form of taxes, the restriction of output, investments of capital to maintain complian 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 througho 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, includi 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 event changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices o 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 consum

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 Scop 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 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 t 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 Isla 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 relie to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. Th 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 feder 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 operatio 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 t reversing deferred tax liabilities.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with GAAP requires management to select appropriat 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 Financia 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 o deferred tax asset valuation allowances in this report, address all important accounting areas where the natur of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary t 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 ga industry. The acquisition of geological and geophysical seismic information, prior to the discovery of prove 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 explorati and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercise 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 adjust prospectively.

At year-end 2019, the remaining $3.5 billion of net capitalized unproved property costs consisted primarily o 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, approximatel $2.1 billion is concentrated in 10 major development areas, the majority of which are not expected to move t 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 commercialization.

Exploratory Costs
For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pendi 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 capitaliz 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, b 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 i 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 developmen 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 expens

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 thes authoritative guidelines. We have trained and experienced internal engineering personnel who estimate 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 change occur, and take into account recent production and subsurface information about each field. Also, as by current authoritative guidelines, the estimated future date when an asset will be permanently shut down fo economic reasons is based on 12-month average prices and current costs. This estimated date when 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 declin 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; recoverabl operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of co 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 consolidate operations were 3.3 billion BOE at the end of 2018 and 3.2 billion BOE at the end of 2019. If the estimates 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 circumstanc indicate a possible significant deterioration in future cash flows expected to be generated by an asset group a 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 developme 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 asse are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there a identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally o 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 futur 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 wh 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 capit 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 th 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 estimate 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 fo 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 amount of an impairment of an investment in any period. See the “APLNG” section of Note 6—Investment 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 ga platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair value of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP& 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 contra 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 decreas to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, 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 properti

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we ha 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 Financia Statements, for additional information.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans a 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, futu 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 projecte 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 determinati 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 und 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 annua benefit expense by $60 million. In determining the discount rate, we use yields on high-quality fixed incom investments matched to the estimated benefit cash flows of our plans. We are also exposed to the 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 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 liabilit shared with other responsible parties. Estimated future costs related to contingencies are subject to change a 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 “Capi Resources and Liquidity” and Note 13—Contingencies and Commitments.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE “SAFE HARBOR” PROVISIONS O 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 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 b incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forwar 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 declin 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, whi 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 futu 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 commodi 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& 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 ga 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 o announced and future exploration and production and LNG development in a timely manner (if at a 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, includi as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under existing or futu 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 regulato 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 hostilitie 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.' 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 o 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 ele 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-I 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 o cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. W 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 Boa of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficien 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 th 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 t 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 th 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 expecte 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.

	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Avera Inter R
Year-End 2019				
2020	**$ -**	**- %**	**$ -**	
2021	**140**	**6.24**	**-**	
2022	**343**	**2.54**	**500**	**2.**
2023	**106**	**7.20**	**-**	
2024	**456**	**3.52**	**-**	
Remaining years	**12,143**	**6.25**	**283**	**1.**
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.
2023	106	7.20	-	
Remaining years	12,599	6.16	283	1.
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 selectiv hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or lo 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 billio 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 woul 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**	20
Sell U.S. dollar, buy British pound	USD	**-**	805	**-**	
Sell Canadian dollar, buy U.S. dollar	CAD	**1,350**	1,250	**(28)**	
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 informatio 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 statemen 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 Sponsorin Organizations of the Treadway Commission in *Internal Control—Integrated Framework (2013).* Based on o 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 December 31, 2019, and their report is included herein.

/s/ Ryan M. Lance	/s/ Don E. Wallette, Jr.
Ryan M. Lance	**Don E. Wallette, Jr.**
Chairman and Chief Executive Officer	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 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 conformi 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 Sponsor 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 an 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 th 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 opinio

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 financ statements and (2) involved our especially challenging, subjective or complex judgments. The communicati of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on 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 uncertaint 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 material impact to earnings given the relatively short remaining useful lives of the asse

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 eff on the determination of the obligations. We also tested management’s controls over th 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 g reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processin yield factors, installed plant operating capacity and approved operating limits. Signific judgment is required by the Company’s internal reservoir engineers in evaluating geological and engineering data when estimating proved oil and gas reserves. Estimati 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 o 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 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 ga reserves.

Our audit procedures included, among others, evaluating the professional qualification and objectivity of the Company's internal reservoir engineers primarily responsible fo 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 evaluate the completeness and accuracy of the financial data and inputs described above used b 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 dri 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 Organizatio of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, ConocoPhillips (the Compar 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 (Unit 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 flo 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 auc We are a public accounting firm registered with the PCAOB and are required to be independent with respect to th 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 anc 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 o 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 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 misstatemen Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may beco 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

Years Ended December 31		Millions of Dollars		
		2019	2018	20
Revenues and Other Income				
Sales and other operating revenues	$	**32,567**	36,417	29,1
Equity in earnings of affiliates		**779**	1,074	7
Gain on dispositions		**1,966**	1,063	2,1
Other income		**1,358**	173	5
Total Revenues and Other Income		**36,670**	38,727	32,5
Costs and Expenses				
Purchased commodities		**11,842**	14,294	12,4
Production and operating expenses		**5,322**	5,213	5,1
Selling, general and administrative expenses		**556**	401	4
Exploration expenses		**743**	369	9
Depreciation, depletion and amortization		**6,090**	5,956	6,8
Impairments		**405**	27	6,6
Taxes other than income taxes		**953**	1,048	8
Accretion on discounted liabilities		**326**	353	3
Interest and debt expense		**778**	735	1,0
Foreign currency transaction (gains) losses		**66**	(17)	
Other expenses		**65**	375	4
Total Costs and Expenses		**27,146**	28,754	35,1
Income (loss) before income taxes		**9,524**	9,973	(2,6
Income tax provision (benefit)		**2,267**	3,668	(1,8
Net income (loss)		**7,257**	6,305	(7
Less: net income attributable to noncontrolling interests		**(68)**	(48)	(
Net Income (Loss) Attributable to ConocoPhillips	$	**7,189**	6,257	(8
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic	$	**6.43**	5.36	(0.
Diluted		**6.40**	5.32	(0.
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,117,260**	1,166,499	1,221,0
Diluted		**1,123,536**	1,175,538	1,221,0

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income **ConocoPhill**

Years Ended December 31		Millions of Dollars		
		2019	2018	20
Net Income (Loss)	**$**	**7,257**	6,305	(7
Other comprehensive income (loss)				
Defined benefit plans				
Prior service credit (cost) arising during the period		**-**	(7)	
Reclassification adjustment for amortization of prior service credit included in net income (loss)		**(35)**	(40)	(
Net change		**(35)**	(47)	(
Net actuarial gain (loss) arising during the period		**(55)**	(150)	
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)		**146**	279	2
Net change		**91**	129	2
Nonsponsored plans*		**(3)**	(1)	
Income taxes on defined benefit plans		**(2)**	(42)	(
Defined benefit plans, net of tax		**51**	39	1
Unrealized holding loss on securities		**-**	-	(
Unrealized loss on securities, net of tax		**-**	-	(
Foreign currency translation adjustments		**699**	(645)	5
Income taxes on foreign currency translation adjustments		**(4)**	3	
Foreign currency translation adjustments, net of tax		**695**	(642)	5
Other Comprehensive Income (Loss), Net of Tax		**746**	(603)	6
Comprehensive Income (Loss)		**8,003**	5,702	(1
Less: comprehensive income attributable to noncontrolling interests		**(68)**	(48)	(
Comprehensive Income (Loss) Attributable to ConocoPhillips	**$**	**7,935**	5,654	(1

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

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet ConocoPhil

At December 31		Millions of Dollars 2019	2
Assets			
Cash and cash equivalents	$	**5,088**	5,9
Short-term investments		**3,028**	2
Accounts and notes receivable (net of allowance of $13 million in 2019 and $25 million in 2018)		**3,267**	3,9
Accounts and notes receivable—related parties		**134**	1
Investment in Cenovus Energy		**2,111**	1,4
Inventories		**1,026**	1,0
Prepaid expenses and other current assets		**2,259**	5
Total Current Assets		**16,913**	13,2
Investments and long-term receivables		**8,687**	9,3
Loans and advances—related parties		**219**	3
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**	45,6
Other assets		**2,426**	1,3
Total Assets	$	**70,514**	69,9
Liabilities			
Accounts Payable	$	**3,176**	3,8
Accounts payable—related parties		**24**	
Short-term debt		**105**	1
Accrued income and other taxes		**1,030**	1,3
Employee benefit obligations		**663**	8
Other accruals		**2,045**	1,2
Total Current Liabilities		**7,043**	7,3
Long-term debt		**14,790**	14,8
Asset retirement obligations and accrued environmental costs		**5,352**	7,6
Deferred income taxes		**4,634**	5,0
Employee benefit obligations		**1,781**	1,7
Other liabilities and deferred credits		**1,864**	1,1
Total Liabilities		**35,464**	37,9
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**	
Capital in excess of par		**46,983**	46,8
Treasury stock (at cost: 2019—710,783,814 shares; 2018—653,288,213 shares)		**(46,405)**	(42,9
Accumulated other comprehensive loss		**(5,357)**	(6,0
Retained earnings		**39,742**	34,0
Total Common Stockholders' Equity		**34,981**	31,9
Noncontrolling interests		**69**	1
Total Equity		**35,050**	32,0
Total Liabilities and Equity	$	**70,514**	69,9

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhil**

Years Ended December 31		Millions of Dollars		
		2019	2018	2
Cash Flows From Operating Activities				
Net income (loss)	$	**7,257**	6,305	(7
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization		**6,090**	5,956	6,8
Impairments		**405**	27	6,6
Dry hole costs and leasehold impairments		**421**	95	5
Accretion on discounted liabilities		**326**	353	3
Deferred taxes		**(444)**	283	(3,6
Undistributed equity earnings		**594**	152	(2
Gain on dispositions		**(1,966)**	(1,063)	(2,1
Other		**(1,000)**	191	(4
Working capital adjustments				
Decrease (increase) in accounts and notes receivable		**505**	235	(8
Decrease (increase) in inventories		**(67)**	86	(
Decrease (increase) in prepaid expenses and other current assets		**37**	(55)	
Increase (decrease) in accounts payable		**(378)**	(52)	2
Increase (decrease) in taxes and other accruals		**(676)**	421	6
Net Cash Provided by Operating Activities		**11,104**	12,934	7,0
Cash Flows From Investing Activities				
Capital expenditures and investments		**(6,636)**	(6,750)	(4,5
Working capital changes associated with investing activities		**(103)**	(68)	1
Proceeds from asset dispositions		**3,012**	1,082	13,8
Net sales (purchases) of investments		**(2,910)**	1,620	(1,7
Collection of advances/loans—related parties		**127**	119	1
Other		**(108)**	154	
Net Cash Provided by (Used in) Investing Activities		**(6,618)**	(3,843)	7,7
Cash Flows From Financing Activities				
Repayment of debt		**(80)**	(4,995)	(7,8
Issuance of company common stock		**(30)**	121	(
Repurchase of company common stock		**(3,500)**	(2,999)	(3,0
Dividends paid		**(1,500)**	(1,363)	(1,3
Other		**(119)**	(123)	(1
Net Cash Used in Financing Activities		**(5,229)**	(9,359)	(12,3
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash		**(46)**	(117)	2
Net Change in Cash, Cash Equivalents and Restricted Cash		**(789)**	(385)	2,7
Cash, cash equivalents and restricted cash at beginning of period		**6,151**	6,536	3,6
Cash, Cash Equivalents and Restricted Cash at End of Period	$	**5,362**	6,151	6,3

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 Cor

	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-Controlli[ng] Intere[sts]
December 31, 2016	$	18	46,507	(36,906)	(6,193)	31,548	25
Net income (loss)						(855)	6
Other comprehensive income					675		
Dividends paid ($1.06 per share of common stock)						(1,305)	
Repurchase of company common stock				(3,000)			
Distributions to noncontrolling interests and other							(12
Distributed under benefit plans			115				
Other						3	
December 31, 2017	$	18	46,622	(39,906)	(5,518)	29,391	19
Net income						6,257	4
Other comprehensive loss					(603)		
Dividends paid ($1.16 per share of common stock)						(1,363)	
Repurchase of company common stock				(2,999)			
Distributions to noncontrolling interests and other							(12
Distributed under benefit plans			257				
Changes in Accounting Principles*					58	(278)	
Other						3	
December 31, 2018	$	18	46,879	(42,905)	(6,063)	34,010	12
Net income						**7,189**	**6**
Other comprehensive income					**746**		
Dividends paid ($1.34 per share of common stock)						**(1,500)**	
Repurchase of company common stock				**(3,500)**			
Distributions to noncontrolling interests and other							**(12**
Distributed under benefit plans			**104**				
Changes in Accounting Principles**					**(40)**	**40**	
Other						**3**	
December 31, 2019	**$**	**18**	**46,983**	**(46,405)**	**(5,357)**	**39,742**	**6**

**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 accoun 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 o similar investment of the same issuer. Undivided interests in oil and gas joint ventures, pipelines, natura 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, Lowe 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 a 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 leg 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 ou 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 sa of inventory with the same counterparty are entered into "in contemplation" of one another, are combin 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 cos 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 tha one year as of the balance sheet date. They are carried at fair value and presented within the "Investmer 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 wit 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 categorize 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-corroborate inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modificatio 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 t fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivativ 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 i 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 cost 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 th 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 plan 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 prove 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 underlyin 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 metho (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 ar asset may not be recovered, the asset is monitored by management through an established process wher 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 o 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 whic 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 pric for long-lived assets, the fair value of impaired assets is typically determined based on the present value 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 base on estimated future production volumes, prices and costs, considering all available evidence at the date 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 ar 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 dow to fair value. The fair value of the impaired investment is based on quoted market prices, if available, o 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 improvement are expensed when incurred.

- **Property Dispositions**—When complete units of depreciable property are sold, the asset cost and relat accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain on dispositions" li 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 retir 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, ou estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over tim 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, o 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 discount 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 whe 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 reliev 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 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 th 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, whethe the award was granted with ratable or cliff vesting.

- **Income Taxes**—Deferred income taxes are computed using the liability method and are provided on al temporary differences between the financial reporting basis and the tax basis of our assets and liabilitie 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 corporat 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 penaltie 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 stoc 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, primaril under the treasury-stock method. Diluted net loss per share, which is calculated the same as basic net lo 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 liabilitie 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 ado 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 ass 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 a corresponding right-of-use assets on our consolidated balance sheet as of January 1, 2019, for leases classifi 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 th 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	**Januar 20**
Equity				
Accumulated other comprehensive loss	$	(6,063)	(40)	**(6,1**
Retained earnings		34,010	40	**34,0**

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 suppo 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 o 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	20
Crude oil and natural gas	$	**472**	43
Materials and supplies		**554**	57
	$	**1,026**	1,00

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 an 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 “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 “Oth 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 end December 31, 2019 and 2017, respectively. The before-tax earnings associated with our interests in Niobrar for the year ended December 31, 2018 was $35 million. This transaction is subject to regulatory approval an 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 of $4 million of PP&E offset by $70 million of associated AROs. 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 (Kuparu
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 t
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 1
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 Cenovu
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 "Ga
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 g
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 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. He Hub price is at or above $3.20 per MMBTU. In 2018, we recorded a gain on dispositions for these continger 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 $ million loss on disposition noted above, was $3.2 billion for 2017. The San Juan Basin results were in our Lower 48 segment. reported

In September 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash aft customary adjustments and recognized a loss on disposition of $28 million. At the time of the disposition, carrying value of our interest was $206 million, consisting primarily of $279 million of PP&E and $72 millio 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 segmen

Note 6—Investments, Loans and Long-Term Receivables

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

		Millions of Dollars	
		2019	20
Equity investments	$	**8,234**	9,00
Loans and advances—related parties		**219**	33
Long-term receivables		**243**	23
Long-term investments in debt securities		**133**	
Other investments		**77**	8
	$	**8,906**	9,66

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 expor LNG.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of Qat 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	20
Revenues	$	**11,310**	11,654	11,55
Income (loss) before income taxes		**3,726**	3,660	(2,87
Net income (loss)		**3,085**	3,244	(1,43

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

		Millions of Dollars	
		2019	20
Current assets	$	**3,289**	3,28
Noncurrent assets		**38,905**	41,56
Current liabilities		**2,603**	2,62
Noncurrent liabilities		**22,168**	23,87

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 milli in 2019, 2018 and 2017, respectively.

APLNG

APLNG is focused on CBM production from the Bowen and Surat basins in Queensland, Australia, to suppl the domestic gas market and on LNG processing and export sales. Our investment in APLNG gives us acces 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 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 fo 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 203

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 t 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 projec finance debt, APLNG made voluntary repayments of $2.2 billion and $1.0 billion to a syndicate of Australia 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 FAS 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 combinatio 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 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 bas 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 i 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 partie

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 issue 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 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 o $649 million from $1.46 billion at December 31, 2018. The increase in fair value represents the net unrealiz 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	20
Beginning balance at January 1	$	**856**	853	1,06
Additions pending the determination of proved reserves		**239**	140	11
Reclassifications to proved properties		**(11)**	(37)	(6
Sales of suspended wells		**(54)**	(93)	
Charged to dry hole expense		**(10)**	(7)	(26
Ending balance at December 31	$	**1,020** *	856	85

**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	20
Exploratory well costs capitalized for a period of one year or less	$	**206**	145	6
Exploratory well costs capitalized for a period greater than one year		**814**	711	78
Ending balance	$	**1,020** *	856	85
Number of projects with exploratory well costs capitalized for a period greater than one year		**23**	24	2

**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 mo than one year since the completion of drilling as of December 31, 2019:

		Millions of Dollars			
			Suspended Since		
		Total	2016–2018	2013–2015	2004–20
Greater Poseidon—Australia(2)(3)		177	-	157	2
NPRA—Alaska(1)		149	111	38	
Barossa/Caldita—Australia(2)(3)		136	59	-	7
Surmont—Canada(1)		118	6	55	5
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	
WL4-00—Malaysia(2)		17	17	-	
Other of $10 million or less each(1)(2)		63	20	26	1
Total	$	814	265	374	17

(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 "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	20
Alaska	**$**	**-**	20	18
Lower 48		**402**	63	3,96
Canada		**2**	9	2
Europe and North Africa		**1**	(79)	4
Asia Pacific and Middle East		**-**	14	2,38
	$	**405**	27	6,60

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 yea 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 ou 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, f 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 ou 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 Dollar	
		2019	20
Asset retirement obligations	$	**6,206**	7,90
Accrued environmental costs		**171**	17
Total asset retirement obligations and accrued environmental costs		**6,377**	8,08
Asset retirement obligations and accrued environmental costs due within one year*		**(1,025)**	(39
Long-term asset retirement obligations and accrued environmental costs	$	**5,352**	7,68

**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 retiremen 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 tak 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 Dollar	
		2019	20
Balance at January 1	$	**7,908**	7,79
Accretion of discount		**322**	34
New obligations		**155**	65
Changes in estimates of existing obligations		**50**	(26
Spending on existing obligations		**(229)**	(22
Property dispositions		**(1,920)**	(16
Foreign currency translation		**(80)**	(24
Balance at December 31	$	**6,206**	7,90

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 pa 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 discount using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmen 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	20
9.125% Debentures due 2021	$ **123**	12
8.20% Debentures due 2025	**134**	13
8.125% Notes due 2030	**390**	39
7.9% Debentures due 2047	**60**	6
7.8% Debentures due 2027	**203**	20
7.65% Debentures due 2023	**78**	7
7.40% Notes due 2031	**500**	50
7.375% Debentures due 2029	**92**	9
7.25% Notes due 2031	**500**	50
7.20% Notes due 2031	**575**	57
7% Debentures due 2029	**200**	20
6.95% Notes due 2029	**1,549**	1,54
6.875% Debentures due 2026	**67**	6
6.50% Notes due 2039	**2,750**	2,75
5.951% Notes due 2037	**645**	64
5.95% Notes due 2036	**500**	50
5.95% Notes due 2046	**500**	50
5.90% Notes due 2032	**505**	50
5.90% Notes due 2038	**600**	60
4.95% Notes due 2026	**1,250**	1,25
4.30% Notes due 2044	**750**	75
4.15% Notes due 2034	**246**	24
3.35% Notes due 2024	**426**	42
3.35% Notes due 2025	**199**	19
2.4% Notes due 2022	**329**	32
Floating rate notes due 2022 at 2.81% – 3.58% during 2019 and 2.32% – 3.52% during 2018	**500**	50
Industrial Development Bonds due 2035 at 1.08% – 2.45% during 2019 and 0.95% – 1.86% during 2018	**18**	1
Marine Terminal Revenue Refunding Bonds due 2031 at 1.08% – 2.45% during 2019 and 0.88% – 1.95% during 2018	**265**	26
Other	**17**	1
Debt at face value	**13,971**	13,97
Finance leases	**720**	77
Net unamortized premiums, discounts and debt issuance costs	**204**	22
Total debt	**14,895**	14,96
Short-term debt	**(105)**	(11
Long-term debt	$ **14,790**	14,85

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 o 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 th 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 workin 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 outstandin borrowings or letters of credit under the revolving credit facility at December 31, 2019 or December 31, 201 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 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 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 expec 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 ownersh interest in APLNG. The following is a description of the guarantees with values calculated utilizing Decemb 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 i October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liabilit arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sal 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. Futu 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 t 26 years or the life of the venture. As of December 31, 2019, we were released from certain of thes guarantees considered subordinated financial support to APLNG. Our remaining maximum potenti 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, guarante 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 temporar continue to support various guarantees and letters of credit which were provided for the benefit of entities th 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 th 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 th 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, se 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 activ 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 continger liability exposures will exceed current accruals by an amount that would have a material adverse impact on o 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 futu 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 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 accoun stakeholder and business considerations. When measuring environmental liabilities, we also consider our pr 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 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 potentia 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 proportiona 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 an 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 royal 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 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 th 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 suc 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 mandate 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. I response to this expropriation, ConocoPhillips initiated international arbitration on November 2, 2007, with t 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 h 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 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. 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 notic of default to PDVSA on October 14 and November 12, 2019, and to date PDVSA failed to cure its breach. A 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
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 seekin 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 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 i 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 connecti 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 Internationa 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 Octob 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 Islar 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 relie to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. Th 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 feder 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 operation 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 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 ar 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 c our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized ga and losses are recognized either on a gross basis if directly related to our physical business or a net basis if h 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	20
Assets			
Prepaid expenses and other current assets	**$**	**288**	41
Other assets		**34**	4
Liabilities			
Other accruals		**283**	37
Other liabilities and deferred credits		**28**	3

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	20
Sales and other operating revenues	**$**	**141**	45	7
Other income		**4**	7	
Purchased commodities		**(118)**	(41)	(6

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

	Open Position Long/(Short)	
	2019	20
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(5)**	(1
Basis	**(23)**	(

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 cas 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	201
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	20
Foreign currency transaction losses	$	**16**	1	1

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

		In Millions Notional Currency	
		2019	20
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy British pound	USD	**-**	80
Sell British pound, buy other currencies*	GBP	**-**	2
Buy British pound, sell euro	GBP	**4**	
Sell Canadian dollar, buy U.S. dollar	CAD	**1,337**	1,24

**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 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. 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 Investment	
		2019	2018	**2019**	2(
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**	2
U.S. Government Obligations					
Remaining maturities from 1 to 90 days		**394**	1,301	**-**	
	$	**5,079**	5,915	**2,929**	2

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	Investment and Long Term Receivable
Corporate Bonds			
Remaining maturities within one year	$ **1**	**59**	
Remaining maturities greater than one year through five years	**-**	**-**	**9**
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	**-**	**-**	**1**
Asset-backed Securities			
Remaining maturities greater than one year through five years	**-**	**-**	**1**
	$ **9**	**99**	**13**

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 Valu
Major Security Type		
Corporate bonds	$ **159**	**15**
Commercial paper	**38**	**3**
U.S. government obligations	**25**	**2**
Asset-backed securities	**19**	**1**
	$ **241**	**24**

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 investment 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 equivalen 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 a 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 receivab 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 owe 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 rever 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 we 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 exi 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. Tho 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 an sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing servi 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, an asset-backed securities that are valued using pricing provided by brokers or pricing service companies th 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 historic relationships among various commodities, modeled market prices, time value, volatility factors and othe 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 recurrin basis):

	Millions of Dollars							
	December 31, 2019				December 31, 2018			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	To
Assets								
Investment in Cenovus Energy	**$ 2,111**	**-**	**-**	**2,111**	1,462	-	-	1,46
Investments in debt securities	**25**	**216**	**-**	**241**				
Commodity derivatives	**172**	**114**	**36**	**322**	236	181	33	4
Total assets	**$ 2,308**	**330**	**36**	**2,674**	1,698	181	33	1,9
Liabilities								
Commodity derivatives	**$ 174**	**115**	**22**	**311**	225	145	30	40
Total liabilities	**$ 174**	**115**	**22**	**311**	225	145	30	40

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	**$**	**194**	**194**	**-**	**-**	**35**
December 31, 2019		**166**	**166**	**-**	**-**	**2**
Equity Method Investments						
March 31, 2019		**171**	**171**	**-**	**-**	**6**
May 31, 2019		**30**	**-**	**30**	**-**	**9**
Year ended December 31, 2018						
Net PP&E (held for sale)						
March 31, 2018	**$**	250	-	-	250	4
September 30, 2018		201	201	-	-	4

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
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 it carrying value, and was written down to fair value. For additional information, see Note 3—Variable Interes 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 Loan and advances—related parties.
- Investment in Cenovus Energy shares: See Note 7—Investment in Cenovus Energy for a discussion 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 account 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 Lev 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**	20
Financial assets				
Investment in Cenovus Energy	$ **2,111**	1,462	**2,111**	1,46
Commodity derivatives	**125**	170	**125**	17
Investments in debt securities	**241**	-	**241**	
Total loans and advances—related parties	**339**	468	**339**	46
Financial liabilities				
Total debt, excluding finance leases	**14,175**	14,191	**18,108**	16,14
Commodity derivatives	**106**	110	**106**	11

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 retur 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	20
Issued			
Beginning of year	**1,791,637,434**	1,785,419,175	1,782,079,10
Distributed under benefit plans	**4,014,769**	6,218,259	3,340,06
End of year	**1,795,652,203**	1,791,637,434	1,785,419,17
Held in Treasury			
Beginning of year	**653,288,213**	608,312,034	544,809,77
Repurchase of common stock	**57,495,601**	44,976,179	63,502,26
End of year	**710,783,814**	653,288,213	608,312,03

Preferred Stock

We have authorized 500 million shares of preferred stock, par value $0.01 per share, none of which was issu 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 i 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 sha 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 tha 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. F 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 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 leas 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 nev 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 o 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, terminatio 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 su options. We use our incremental borrowing rate as the discount rate in determining the present value of futu 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 asset 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, w 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 activitie 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 cou 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 proportion basis consistent with its ownership interest in the investee company. In addition, the company has historical recorded finance lease assets and liabilities associated with certain oil and gas joint ventures on a proportion 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 subj to reconsideration upon the modification or other required reassessment of the arrangements prior to lease te 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, respectiv

The following table summarizes our lease costs for 2019:

	Millions of Dollars
	2019
Lease Cost*	
Operating lease cost	$ 3
Finance lease cost	
Amortization of right-of-use assets	
Interest on lease liabilities	
Short-term lease cost**	
Total lease cost***	$ 5

*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.
Finance leases	8.
Weighted-average discount rate (percent)	
Operating leases	3.
Finance leases	5.

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	$	2
Operating cash flows from finance leases		
Financing cash flows from finance leases		
Right-of-use assets obtained in exchange for operating lease liabilities	$	4
Right-of-use assets obtained in exchange for finance lease liabilities		

**The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers. I addition, pursuant to other applicable accounting guidance, lease payments made in connection with preparing another asset for its intended 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	Finan Leas
Maturity of Lease Liabilities			
2020	$	348	12
2021		247	10
2022		130	10
2023		82	8
2024		63	8
Remaining years		149	38
Total*		1,019	88
Less: portion representing imputed interest		(87)	(16
Total lease liabilities	$	932	72

**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:

		Millio of Doll
2019	$	11
2020		11
2021		10
2022		9
2023		8
Remaining years		45
Total		97
Less: portion representing imputed interest		(19
Capital lease obligations	$	77

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

		Millio of Doll
2019	$	2
2020		4
2021		1
2022		3
2023		
Remaining years		2
Total		1,39
Less: income from subleases		(
Net minimum operating lease payments	$	1,38

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

		Millions of Dollars	
		2018	20
Total rentals	$	253	2
Less: sublease rentals		(16)	(2
	$	237	24

Note 18—Employee Benefit Plans

Pension and Postretirement Plans

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

	Millions of Dollars						
	Pension Benefits				Other Benefits	
	2019		2018		**2019**	20
	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**	26
Service cost	**79**	**69**	83	81	**1**	
Interest cost	**79**	**97**	99	107	**8**	
Plan participant contributions	**-**	**2**	-	2	**20**	2
Plan amendments	**-**	**-**	-	7	**-**	
Actuarial (gain) loss	**278**	**387**	(44)	(259)	**27**	(1
Benefits paid	**(253)**	**(147)**	(507)	(143)	**(59)**	(6
Curtailment	**-**	**(69)**	(4)	(3)	**-**	
Settlement	**-**	**-**	(730)	-	**-**	
Recognition of termination benefits	**-**	**1**	3	-	**-**	
Foreign currency exchange rate change	**-**	**102**	-	(199)	**1**	(
Benefit obligation at December 31*	$ **2,319**	**3,880**	2,136	3,438	**216**	21
**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**	4
Plan participant contributions	**-**	**2**	-	2	**20**	2
Benefits paid	**(253)**	**(147)**	(507)	(143)	**(59)**	(6
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)**	(21

	Millions of Dollars					
	Pension Benefits				Other Benefit	
	2019		2018		**2019**	2(
	U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ **-**	**765**	-	232	**-**	
Current liabilities	**(21)**	**(6)**	(59)	(4)	**(42)**	(
Noncurrent liabilities	**(707)**	**(333)**	(741)	(308)	**(174)**	(1
Total recognized	$ **(728)**	**426**	(800)	(80)	**(216)**	(2
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**3.25 %**	**2.35**	4.25	3.05	**3.10**	4.
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.
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 eac 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:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2019		2018		**2019**	20
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial (gain) loss	$ **479**	**227**	516	310	**8**	(2
Unrecognized prior service cost (credit)	**-**	**(2)**	-	(4)	**(183)**	(21

		Millions of Dollars					
		Pension Benefits				Other Benefit	
		2019		2018		**2019**	20
		U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)							
Net gain (loss) arising during the period	**$**	**(79)**	**51**	(177)	17	**(27)**	
Amortization of actuarial (gain) loss included in income (loss)*		**116**	**32**	249	31	**(2)**	
Net change during the period	**$**	**37**	**83**	72	48	**(29)**	
Prior service credit (cost) arising during the period	**$**	**-**	**-**	-	(7)	**-**	
Amortization of prior service cost (credit) included in income (loss)		**-**	**(2)**	-	(5)	**(33)**	(
Net change during the period	**$**	**-**	**(2)**	-	(12)	**(33)**	(

**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 Benefit
		U.S.	Int'l.	
Unrecognized net actuarial (gain) loss	**$**	**50**	**23**	
Unrecognized prior service credit		**-**	**(2)**	**(3**

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 ar 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	20
		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	
Interest cost		**79**	**97**	99	107	118	103	**8**	8	
Expected return on plan assets		**(74)**	**(138)**	(114)	(155)	(132)	(158)	**-**	-	
Amortization of prior service cost (credit)		**-**	**(2)**	-	(5)	4	(6)	**(33)**	(35)	(3
Recognized net actuarial loss (gain)		**54**	**32**	53	31	69	50	**(2)**	(1)	(
Settlements		**62**	**-**	196	-	131	-	**-**	-	
Net periodic benefit cost	$	**200**	**58**	317	59	279	66	**(26)**	(27)	(2

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

In 2018, we purchased a group annuity contract from Prudential and transferred $730 million of future benef obligations from the U.S. qualified pension plan to Prudential. The purchase of the group annuity contract w funded directly by plan assets of the U.S. qualified pension plan. Effective January 1, 2019, the Cash Balanc 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 interes 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 i 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, 201 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 straig line basis over the average remaining service period of employees expected to receive benefits under the pla 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 202 that increases to 5 percent by 2028. A one-percentage-point change in the assumed health care cost trend rat 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 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 investmen 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 deb securities categorized in Level 2 are estimated using recently executed transactions and quoted mark 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., observabl 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 o 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 owe 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 marke 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 $14 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 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	To
2019								
Equity securities								
U.S.	$ **94**	**-**	**7**	**101**	**435**	**-**	**-**	**43**
International	**98**	**-**	**-**	**98**	**266**	**-**	**-**	**26**
Mutual funds	**93**	**-**	**-**	**93**	**245**	**267**	**-**	**51**
Debt securities								
Government	**-**	**-**	**-**	**-**	**1,412**	**-**	**-**	**1,41**
Corporate	**-**	**2**	**-**	**2**	**-**	**-**	**-**	
Mutual funds	**-**	**-**	**-**	**-**	**392**	**-**	**-**	**39**
Cash and cash equivalents	**-**	**-**	**-**	**-**	**98**	**-**	**-**	**9**
Derivatives	**-**	**-**	**-**	**-**	**11**	**-**	**-**	**1**
Real estate	**-**	**-**	**-**	**-**	**-**	**-**	**132**	**13**
Total in fair value hierarchy	$ **285**	**2**	**7**	**294**	**2,859**	**267**	**132**	**3,2**
Investments measured at net asset value*								
Equity securities								
Common/collective trusts	$ **-**	**-**	**-**	**457**	**-**	**-**	**-**	**16**
Debt securities								
Common/collective trusts	**-**	**-**	**-**	**637**	**-**	**-**	**-**	**70**
Cash and cash equivalents	**-**	**-**	**-**	**25**	**-**	**-**	**-**	
Real estate	**-**	**-**	**-**	**83**	**-**	**-**	**-**	**11**
Total**	$ **285**	**2**	**7**	**1,496**	**2,859**	**267**	**132**	**4,29**

**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	To
2018									
Equity securities									
U.S.	$	74	-	20	94	371	-	-	37
International		80	-	-	80	241	-	-	24
Mutual funds		76	-	-	76	213	181	-	39
Debt securities									
Government		-	-	-	-	889	-	-	88
Corporate		-	2	-	2	-	-	-	
Mutual funds		-	-	-	-	363	-	-	36
Cash and cash equivalents		-	-	-	-	71	-	-	7
Time deposits		-	-	-	-	6	-	-	
Derivatives		-	-	-	-	(17)	-	-	(
Real estate		-	-	-	-	-	-	124	12
Total in fair value hierarchy	$	230	2	20	252	2,137	181	124	2,44
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$	-	-	-	364	-	-	-	15
Debt securities									
Common/collective trusts		-	-	-	548	-	-	-	64
Cash and cash equivalents		-	-	-	5	-	-	-	
Real estate		-	-	-	80	-	-	-	10
Total**	$	230	2	20	1,249	2,137	181	124	3,34

**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 Retiremen 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 $3 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $90 million 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 contra
and which reflect expected future service, as appropriate, are expected to be paid:

		Millions of Dollars		
		Pension Benefits		Other Benefit
		U.S.	Int'l.	
2020	$	447	150	3
2021		270	156	2
2022		250	158	2
2023		217	163	2
2024		220	170	2
2025–2029		822	927	6

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

		Millions of Dolla
Balance at December 31, 2018	$	
Accruals		
Benefit payments		(
Balance at December 31, 2019	**$**	

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 elect 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 ou
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 comm
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 continu 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 th 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 tim We recognize expense on a straight-line basis over the service period for the entire award, whether the awar 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	20
Compensation cost	$	**274**	265	22
Tax benefit		**71**	64	7

Stock Options—Stock options granted under the provisions of the Plan and prior plans permit purchase of c common stock at exercise prices equivalent to the average fair market value of ConocoPhillips common stoc 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 c grant. Options awarded to certain employees already eligible for retirement vest within six months of the gra 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 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 c

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:

	Options		Weighted-Average Exercise Price		Millions of Doll Aggreg Intrinsic Va
Outstanding at December 31, 2018	19,379,677	$	52.88	$	2
Exercised	**(1,339,480)**		**36.28**		[illegible]
Forfeited	-				
Expired or cancelled	-				
Outstanding at December 31, 2019	**18,040,197**	**$**	**54.11**	**$**	**2**
Vested at December 31, 2019	**17,922,026**	**$**	**54.14**	**$**	**2**
Exercisable at December 31, 2019	**17,172,815**	**$**	**54.33**	**$**	**1**

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-grant date fair value of stock option awards granted during 2017 was average $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 ho 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 p unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those un 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 quarter cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value 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 equa to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that w 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 Doll
				Total Fair Val
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**	**$ 22**
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 w $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 schedu 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 ar 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 Doll
				Total Fair Val
Outstanding at December 31, 2018	376,608	$	62.21	
Granted	**319,552**		**68.20**	
Forfeited	**(6,914)**		**61.35**	
Issued	**(92,255)**		**61.61**	**$**
Outstanding at December 31, 2019	**596,991**	**$**	**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 an 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 201 PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 5 with five years of service or five years after the grant date of the award, and restrictions do not lapse until th 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 aware 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 o dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future gran 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:

	Stock Units	Weighted-Average Grant Date Fair Value		Millions of Doll
				Total Fair Val
Outstanding at December 31, 2018	2,335,542	$	50.45	
Granted	**77,841**		**68.90**	
Forfeited	**-**			
Issued	**(388,559)**		**53.66**	**$ 2**
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 grant during 2018 and 2017 was $53.28 and $49.76, respectively. The total fair value of stock-settled PSUs 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 new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, abse 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 the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending or 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 t 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 performar 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 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 Doll Total Fair Val
Outstanding at December 31, 2018	1,131,007	$ 62.21	
Granted	**1,958,043**	**68.90**	
Forfeited	**-**		
Settled	**(2,479,776)**	**69.10**	**$ 17**
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 grante 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 t conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near t 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 targe 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, t initial target PSU awards terminated at the end of the three-year performance period and were settled after t 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 restrict stock units that were either issued as part of our non-employee director compensation program for current an 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 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 Doll Total Fair Val
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**	**$ 1**
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 granted awards 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
Income Taxes			
Federal			
Current	**$**	**18**	4
Deferred		**(113)**	545
Foreign			
Current		**2,545**	3,273
Deferred		**(323)**	(166)
State and local			
Current		**148**	108
Deferred		**(8)**	(96)
	$	**2,267**	3,668

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 compone of deferred tax liabilities and assets at December 31 were:

		Millions of Dollars	
		2019	
Deferred Tax Liabilities			
PP&E and intangibles	$	**8,660**	8
Inventory		**35**	
Deferred state income tax		**-**	
Other		**234**	
Total deferred tax liabilities		**8,929**	8
Deferred Tax Assets			
Benefit plan accruals		**542**	
Asset retirement obligations and accrued environmental costs		**2,339**	2
Investments in joint ventures		**1,722**	
Other financial accruals and deferrals		**777**	
Loss and credit carryforwards		**8,968**	2
Other		**345**	
Total deferred tax assets		**14,693**	6
Less: valuation allowance		**(10,214)**	(3
Net deferred tax assets		**4,479**	3
Net deferred tax liabilities	$	**4,450**	4

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 taxe of $442 million and $5,021 million, respectively.

At December 31, 2019, the components of our loss and credit carryforwards before and after consideration o the applicable valuation allowances were:

	Millions of Dollars			
		Gross Deferred Tax Asset	Net Deferred Tax Asset After Valuation Allowance	Expiration Net Deferr Tax As
U.S. foreign tax credits	$	7,696	14	20
U.S. general business credits		250	250	2036-20
U.S. capital loss		202	32	20
State net operating losses and tax credits		370	50	Vario
Foreign net operating losses and tax credits		450	413	Post 20
	$	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 t the U.S. Tax Cuts and Jobs Act (Tax Legislation including ongoing issuance of tax regulations related to suc 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, w 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 201
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 tax have not been provided on this amount, as we do not plan to initiate any action that would require the payme 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	20
Balance at January 1	**$**	**1,081**	882	38
Additions based on tax positions related to the current year		**9**	268	61
Additions for tax positions of prior years		**120**	43	10
Reductions for tax positions of prior years		**(22)**	(73)	(12
Settlements		**(9)**	(35)	(
Lapse of statute		**(2)**	(4)	(8
Balance at December 31	**$**	**1,177**	1,081	88

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. Th 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 earnin 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 federa
statutory rate with the provision for income taxes, were:

		Millions of Dollars			Percent of Pre-Tax Income (Loss		
		2019	2018	2017	**2019**	2018	20
Income (loss) before income taxes							
United States	$	**4,704**	2,867	(5,250)	**49.4 %**	28.7	200
Foreign		**4,820**	7,106	2,635	**50.6**	71.3	(100
	$	**9,524**	9,973	(2,615)	**100.0 %**	100.0	100
Federal statutory income tax	$	**2,000**	2,095	(915)	**21.0 %**	21.0	35
Non-U.S. effective tax rates		**1,399**	1,766	625	**14.7**	17.7	(23
Tax Legislation		**-**	(10)	(852)	**-**	(0.1)	32
Canada disposition		**-**	-	(1,277)	**-**	-	48
U.K. disposition		**(732)**	(150)	-	**(7.7)**	(1.5)	
Recovery of outside basis		**(77)**	(21)	(962)	**(0.8)**	(0.2)	36
Adjustment to tax reserves		**9**	(4)	881	**0.1**	-	(33
Adjustment to valuation allowance		**(225)**	(26)	-	**(2.4)**	(0.3)	
APLNG impairment		**-**	-	834	**-**	-	(31
State income tax		**123**	135	(84)	**1.3**	1.4	3
Malaysia Deepwater Incentive		**(164)**	-	-	**(1.7)**	-	
Enhanced oil recovery credit		**(27)**	(99)	(68)	**(0.3)**	(1.0)	2
Other		**(39)**	(18)	(4)	**(0.4)**	(0.2)	0
	$	**2,267**	3,668	(1,822)	**23.8 %**	36.8	69

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. tax benefit of approximately $285 million. The remaining U.S. capital loss has been recorded as a deferred ta asset fully offset with a valuation allowance. See Note 5—Asset Acquisitions and Dispositions, for addition 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 i 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 anc 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 t rate to 21 percent from 35 percent, requiring companies to pay a one-time transition tax on earnings of certai 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, f 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 propos by the U.S. Department of the Treasury and the Internal Revenue Service, we finalized our calculations of th 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 whic 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 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 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 Canad 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 restructurin 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 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 abo 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	Accumulat Oth Comprehensi Lo
December 31, 2016	$	(547)	-	(5,646)	(6,19
Other comprehensive income (loss)		147	(58)	586	67
December 31, 2017		(400)	(58)	(5,060)	(5,51
Other comprehensive income (loss)		39	-	(642)	(60
Cumulative effect of adopting ASU No. 2016-01*		-	58	-	5
December 31, 2018		(361)	-	(5,702)	(6,06
Other comprehensive income		**51**	**-**	**695**	**74**
Cumulative effect of adopting ASU No. 2018-02**		**(40)**	**-**	**-**	**(4**
December 31, 2019	**$**	**(350)**	**-**	**(5,007)**	**(5,35**

**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 completi of our sale of two ConocoPhillips U.K. subsidiaries. For additional information related to this disposition, se 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 yea ended December 31:

	Millions of Dollars		
		2019	20
Defined Benefit Plans	**$**	**88**	18
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	*$*	*23*	
See Note 18—Employee Benefit Plans, for additional information.			

Note 21—Cash Flow Information

		Millions of Dollars		
		2019	2018	20
Noncash Investing Activities				
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	$	**205**	395	(3
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	1,16
Income taxes		**2,905**	2,976	1,16
Net Sales (Purchases) of Investments				
Short-term investments purchased	$	**(4,902)**	(1,953)	(6,61
Short-term investments sold		**2,138**	3,573	4,82
Investments and long-term receivables purchased		**(146)**	-	
	$	**(2,910)**	1,620	(1,79

**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 settlemen agreement related to an award issued by the ICC Tribunal in 2018. We collected $262 million and $75 milli 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 Commitment

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	20
Interest and Debt Expense				
Incurred				
Debt	$	**799**	838	1,11
Other		**36**	67	10
		835	905	1,21
Capitalized		**(57)**	(170)	(11
Expensed	$	**778**	735	1,09
Other Income				
Interest income	$	**166**	97	11
Unrealized gains (losses) on Cenovus Energy common shares*		**649**	(437)	
Other, net		**543**	513	41
	$	**1,358**	173	52

**See Note 7—Investment in Cenovus Energy, for additional information.*

Research and Development Expenditures—expensed	$	**82**	78	10
Shipping and Handling Costs	$	**1,008**	1,075	1,05
Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**-**	-	
Lower 48		**-**	-	
Canada		**5**	(11)	
Europe and North Africa		**-**	(26)	
Asia Pacific and Middle East		**31**	3	2
Other International		**1**	-	
Corporate and Other		**21**	21	(
	$	**58**	(13)	3

	Millions of Dollar	
	2019	20
Properties, Plants and Equipment		
Proved properties	$ **88,284** *	100,6
Unproved properties	**3,980** *	4,6
Other	**5,482**	5,2
Gross properties, plants and equipment	**97,746**	110,5
Less: Accumulated depreciation, depletion and amortization	**(55,477)***	(64,8
Net properties, plants and equipment	$ **42,269**	45,6

**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 employe

Significant transactions with our equity affiliates were:

		Millions of Dollars		
		2019	2018	20
Operating revenues and other income	$	**89**	98	10
Purchases		**38**	98	9
Operating expenses and selling, general and administrative expenses		**65**	60	5
Net interest (income) expense*		**(13)**	(14)	(1

**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	20
Revenue from contracts with customers	$	**26,106**	28,098	20,5
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative		**6,558**	8,218	8,6
Financial derivative contracts		**(97)**	101	(
Consolidated sales and other operating revenues	$	**32,567**	36,417	29,1

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 polic 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	20
Revenue from Outside the Scope of ASC Topic 606 by Segment				
Lower 48	$	**4,989**	6,358	6,3
Canada		**691**	629	8
Europe and North Africa		**878**	1,231	1,5
Physical contracts meeting the definition of a derivative	$	**6,558**	8,218	8,6

		Millions of Dollars		
		2019	2018	20
Revenue from Outside the Scope of ASC Topic 606 by Product				
Crude oil	**$**	**804**	1,112	5
Natural gas		**5,313**	6,734	7,8
Other		**441**	372	2
Physical contracts meeting the definition of a derivative	**$**	**6,558**	8,218	8,6

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 eac 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 partial 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) onc delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical gas sale 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 tra 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 relatec 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 th 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	$	**20**
Contractual payments received		**7**
Revenue recognized		**(19**
At December 31, 2019	$	**8**

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 worldwi basis. We manage our operations six operating segments, which are primarily defined by geographi region through 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, includi 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 a prices that approximate market.

Analysis of Results by Operating Segment

		Millions of Dollars		
		2019	2018	20
Sales and Other Operating Revenues				
Alaska	$	**5,483**	5,740	4,22
Lower 48		**15,514**	17,029	12,96
Intersegment eliminations		**(46)**	(40)	(
Lower 48		**15,468**	16,989	12,96
Canada		**2,910**	3,184	3,17
Intersegment eliminations		**(1,141)**	(1,160)	(55
Canada		**1,769**	2,024	2,61
Europe and North Africa		**5,101**	6,635	5,18
Asia Pacific and Middle East		**4,525**	4,861	4,01
Other International		**-**	-	
Corporate and Other		**221**	168	10
Consolidated sales and other operating revenues	$	**32,567**	36,417	29,10
Depreciation, Depletion, Amortization and Impairments				
Alaska	$	**805**	760	1,02
Lower 48		**3,224**	2,370	6,69
Canada		**232**	324	46
Europe and North Africa		**887**	1,041	1,31
Asia Pacific and Middle East		**1,285**	1,382	3,81
Other International		**-**	-	
Corporate and Other		**62**	106	13
Consolidated depreciation, depletion, amortization and impairments	$	**6,495**	5,983	13,44

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	20
Equity in Earnings of Affiliates				
Alaska	$	**7**	6	
Lower 48		**(159)**	1	
Canada		**-**	-	1
Europe and North Africa		**16**	16	
Asia Pacific and Middle East		**915**	1,051	5
Other International		**-**	-	
Corporate and Other		**-**	-	
Consolidated equity in earnings of affiliates	$	**779**	1,074	7
Income Taxes				
Alaska	$	**472**	376	(68
Lower 48		**137**	474	(2,45
Canada		**(43)**	(96)	(61
Europe and North Africa		**1,435**	2,265	1,16
Asia Pacific and Middle East		**491**	722	35
Other International		**8**	30	2
Corporate and Other		**(233)**	(103)	39
Consolidated income taxes	$	**2,267**	3,668	(1,82
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$	**1,520**	1,814	1,46
Lower 48		**436**	1,747	(2,37
Canada		**279**	63	2,56
Europe and North Africa		**2,724**	1,866	55
Asia Pacific and Middle East		**1,929**	2,070	(1,09
Other International		**263**	364	16
Corporate and Other		**38**	(1,667)	(2,13
Consolidated net income (loss) attributable to ConocoPhillips	$	**7,189**	6,257	(85
Investments in and Advances to Affiliates				
Alaska	$	**83**	86	5
Lower 48		**35**	378	40
Canada		**-**	-	
Europe and North Africa		**54**	55	5
Asia Pacific and Middle East		**8,281**	8,821	9,07
Other International		**-**	-	
Corporate and Other		**-**	-	
Consolidated investments in and advances to affiliates	$	**8,453**	9,340	9,59

		Millions of Dollars		
		2019	2018	20
Total Assets				
Alaska	$	**15,453**	14,648	12,1
Lower 48		**14,425**	14,888	14,6
Canada		**6,350**	5,748	6,2
Europe and North Africa		**8,121**	9,883	11,8
Asia Pacific and Middle East		**14,716**	16,151	16,9
Other International		**285**	89	
Corporate and Other		**11,164**	8,573	11,4
Consolidated total assets	$	**70,514**	69,980	73,3
Capital Expenditures and Investments				
Alaska	$	**1,513**	1,298	81
Lower 48		**3,394**	3,184	2,13
Canada		**368**	477	20
Europe and North Africa		**708**	877	87
Asia Pacific and Middle East		**584**	718	48
Other International		**8**	6	2
Corporate and Other		**61**	190	6
Consolidated capital expenditures and investments	$	**6,636**	6,750	4,59
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	10
Interest and debt expense				
Corporate and Other	$	**778**	735	1,09
Sales and Other Operating Revenues by Product				
Crude oil	$	**18,482**	19,571	13,26
Natural gas		**8,715**	10,720	10,77
Natural gas liquids		**814**	1,114	1,10
Other*		**4,556**	5,012	3,97
Consolidated sales and other operating revenues by product	$	**32,567**	36,417	29,10

**Includes LNG and bitumen.*

Geographic Information

		Millions of Dollars					
		Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
		2019	2018	2017	**2019**	2018	20
United States[3]	$	**21,159**	22,740	17,204	**26,566**	26,838	23,62
Australia and Timor-Leste[4]		**1,647**	1,798	1,448	**7,228**	9,301	9,65
Canada		**1,769**	2,024	2,619	**5,769**	5,333	5,61
China		**772**	836	712	**1,447**	1,380	1,27
Indonesia		**875**	886	757	**605**	669	75
Libya		**1,103**	1,142	586	**668**	679	69
Malaysia		**1,230**	1,346	1,103	**1,871**	2,327	2,73
Norway		**2,349**	2,886	2,348	**5,258**	5,582	6,15
United Kingdom		**1,649**	2,606	2,248	**2**	1,583	3,33
Other foreign countries		**14**	153	81	**1,308**	1,346	1,42
Worldwide consolidated	$	**32,567**	36,417	29,106	**50,722**	55,038	55,27

(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.

Oil and Gas Operations (Unaudited)

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 sha 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 disclosure 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 hel 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, the our applicable reserve quantities would decline. At December 31, 2019, approximately 6 percent of our tota 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 SE 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 d forward, from known reservoirs, and under existing economic conditions, operating methods, and governme 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 usec 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 cos 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 prove 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 reser 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 da analogy and statistical analysis.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination anc 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 Manage 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 c technical issues throughout the year. All of our proved reserves held by consolidated companies and our sha 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 3 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 balanc calculations, reservoir simulation models, well performance data, operating procedures and relevant econom criteria. Management's intent in retaining D&M to review its processes and controls was to provide objectiv 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 review 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. Th 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 internationa 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	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2016	837	506	1,343	13	303	185	203
Revisions	113	65	178	1	38	32	-
Improved recovery	6	-	6	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	41	210	251	-	-	2	-
Production	(60)	(64)	(124)	(1)	(45)	(34)	(7
Sales	-	(10)	(10)	(12)	-	-	-
End of 2017	937	707	1,644	1	296	185	196
Revisions	72	(90)	(18)	2	24	6	5
Improved recovery	2	-	2	-	-	-	-
Purchases	233	1	234	-	-	-	-
Extensions and discoveries	48	179	227	2	2	1	-
Production	(59)	(82)	(141)	(1)	(40)	(33)	(13
Sales	-	(12)	(12)	-	(36)	-	-
End of 2018	1,233	703	1,936	4	246	159	188
Revisions	40	(36)	4	(1)	18	(5)	23
Improved recovery	7	-	7	-	-	-	-
Purchases	-	1	1	-	-	-	-
Extensions and discoveries	25	226	251	2	-	11	-
Production	(74)	(95)	(169)	-	(36)	(31)	(14
Sales	-	(2)	(2)	-	(30)	-	-
End of 2019	1,231	797	2,028	5	198	134	197
Equity affiliates							
End of 2016	-	-	-	-	-	88	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	83	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	78	-
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	73	-
Total company							
End of 2016	837	506	1,343	13	303	273	203
End of 2017	937	707	1,644	1	296	268	196
End of 2018	1,233	703	1,936	4	246	237	188
End of 2019	1,231	797	2,028	5	198	207	197

Years Ended December 31	Crude Oil						
	Millions of Barrels						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa
Developed							
Consolidated operations							
End of 2016	747	256	1,003	13	184	106	203
End of 2017	828	315	1,143	1	190	121	196
End of 2018	1,058	346	1,404	2	192	113	185
End of 2019	1,048	334	1,382	3	149	94	181
Equity affiliates							
End of 2016	-	-	-	-	-	88	-
End of 2017	-	-	-	-	-	83	-
End of 2018	-	-	-	-	-	78	-
End of 2019	-	-	-	-	-	73	-
Undeveloped							
Consolidated operations							
End of 2016	90	250	340	-	119	79	-
End of 2017	109	392	501	-	106	64	-
End of 2018	175	357	532	2	54	46	3
End of 2019	183	463	646	2	49	40	16
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, p offset by downward price revisions of 34 million barrels. Upward revisions in Europe and Africa were prim infill drilling and technical revisions. Downward revisions in Lower 48 were due to changes in developmen specific well locations from the unconventional plays of 71 million barrels and price revisions of 22 million partially offset by upward revisions related to infill drilling and improved well performance of 57 million ba

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific locations from the unconventional plays and are more than offset by increases in planned well locations in th unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to d timing were partially offset by higher prices. Revisions in Alaska, Europe and Asia Pacific/Middle East were due to higher prices.

  In 2017, revisions in Alaska, Lower 48, Europe and Asia Pacific/Middle East were primarily due to higher p

- *Purchases:* In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acqu

- *Extensions and discoveries*: In 2019, extensions and discoveries in Lower 48 were due to planned developm specific well locations from the unconventional plays which more than offset the decreases in the revisions c In Asia Pacific/Middle East, increases were due to sanctioning of development programs in China and Malay

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy specific well locations from the unconventional plays. Extensions and discoveries in Alaska were driven by success in Western North Slope.

  In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Perm 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 t disposition of a subsidiary that held 16.5 percent of our 24 percent interest in the Clair Field in the U.K. In 2 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
Developed and Undeveloped						
Consolidated operations						
End of 2016	107	278	385	48	19	5
Revisions	4	29	33	-	2	1
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	71	71	-	-	1
Production	(5)	(24)	(29)	(3)	(3)	(2)
Sales	-	(130)	(130)	(44)	-	-
End of 2017	106	224	330	1	18	5
Revisions	5	(25)	(20)	-	1	(1)
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	69	69	-	1	-
Production	(5)	(25)	(30)	-	(3)	(1)
Sales	-	(21)	(21)	-	-	-
End of 2018	106	222	328	1	17	3
Revisions	(1)	(11)	(12)	-	3	(1)
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	62	62	1	-	-
Production	(5)	(28)	(33)	-	(3)	(1)
Sales	-	-	-	-	(4)	-
End of 2019	100	245	345	2	13	1
Equity affiliates						
End of 2016	-	-	-	-	-	47
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(2)
Sales	-	-	-	-	-	-
End of 2017	-	-	-	-	-	45
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3)
Sales	-	-	-	-	-	-
End of 2018	-	-	-	-	-	42
Revisions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-
Production	-	-	-	-	-	(3)
Sales	-	-	-	-	-	-
End of 2019	-	-	-	-	-	39
Total company						
End of 2016	107	278	385	48	19	52
End of 2017	106	224	330	1	18	50
End of 2018	106	222	328	1	17	45
End of 2019	100	245	345	2	13	40

Years Ended December 31	Natural Gas Liquids					
	Millions of Barrels					
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East
Developed						
Consolidated operations						
End of 2016	107	209	316	47	15	5
End of 2017	106	101	207	1	16	2
End of 2018	106	97	203	-	15	3
End of 2019	100	99	199	1	10	1
Equity affiliates						
End of 2016	-	-	-	-	-	47
End of 2017	-	-	-	-	-	45
End of 2018	-	-	-	-	-	42
End of 2019	-	-	-	-	-	39
Undeveloped						
Consolidated operations						
End of 2016	-	69	69	1	4	-
End of 2017	-	123	123	-	2	3
End of 2018	-	125	125	1	2	-
End of 2019	-	146	146	1	3	-
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 specifi locations from the unconventional plays of 32 million barrels and price revisions of 11 million barrels, parti 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 locations from the unconventional plays and are more than offset by increases in planned well locations in th 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 developm specific well locations from the unconventional plays which more than offset the decreases in the revisions c

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy specific well locations from the unconventional plays.

  In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Perr Unconventional, Eagle Ford and Bakken.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Lower 48 sales were prim the disposition of our interests in the Barnett. In 2017, Lower 48 sales were due to the disposition of our int San Juan Basin and Panhandle assets, while Canada sales were due to the disposition of a majority of our we Canada assets.

Years Ended December 31	Natural Gas						
	Billions of Cubic Feet						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2016	2,102	4,714	6,816	1,037	1,238	1,526	227
Revisions	287	460	747	8	167	16	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	2	582	584	3	-	23	-
Production	(71)	(338)	(409)	(71)	(188)	(267)	(3
Sales	-	(2,885)	(2,885)	(966)	-	-	-
End of 2017	2,320	2,533	4,853	11	1,217	1,298	224
Revisions	150	(283)	(133)	9	86	4	-
Improved recovery	-	-	-	-	-	-	-
Purchases	335	1	336	-	-	-	-
Extensions and discoveries	2	527	529	11	110	23	-
Production	(71)	(237)	(308)	(5)	(188)	(246)	(10
Sales	-	(223)	(223)	-	(13)	-	-
End of 2018	2,736	2,318	5,054	26	1,212	1,079	214
Revisions	30	(113)	(83)	(2)	160	147	21
Improved recovery	-	-	-	-	-	-	-
Purchases	-	2	2	-	-	-	-
Extensions and discoveries	7	483	490	23	-	1	-
Production	(85)	(252)	(337)	(4)	(178)	(250)	(11
Sales	-	(7)	(7)	-	(298)	-	-
End of 2019	2,688	2,431	5,119	43	896	977	224
Equity affiliates							
End of 2016	-	-	-	-	-	4,381	-
Revisions	-	-	-	-	-	111	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	185	-
Production	-	-	-	-	-	(374)	-
Sales	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	4,303	-
Revisions	-	-	-	-	-	280	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	362	-
Production	-	-	-	-	-	(381)	-
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	4,564	-
Revisions	-	-	-	-	-	(7)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	252	-
Production	-	-	-	-	-	(388)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	4,421	-
Total company							
End of 2016	2,102	4,714	6,816	1,037	1,238	5,907	227
End of 2017	2,320	2,533	4,853	11	1,217	5,601	224
End of 2018	2,736	2,318	5,054	26	1,212	5,643	214
End of 2019	2,688	2,431	5,119	43	896	5,398	224

Years Ended December 31	Natural Gas						
	Billions of Cubic Feet						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afric
Developed							
Consolidated operations							
End of 2016	2,094	4,199	6,293	1,031	998	1,188	227
End of 2017	2,310	1,597	3,907	11	997	945	224
End of 2018	2,720	1,427	4,147	17	1,052	758	214
End of 2019	2,601	1,398	3,999	30	697	843	224
Equity affiliates							
End of 2016	-	-	-	-	-	4,110	-
End of 2017	-	-	-	-	-	4,044	-
End of 2018	-	-	-	-	-	4,059	-
End of 2019	-	-	-	-	-	3,898	-
Undeveloped							
Consolidated operations							
End of 2016	8	515	523	6	240	338	-
End of 2017	10	936	946	-	220	353	-
End of 2018	16	891	907	9	160	321	-
End of 2019	87	1,033	1,120	13	199	134	-
Equity affiliates							
End of 2016	-	-	-	-	-	271	-
End of 2017	-	-	-	-	-	259	-
End of 2018	-	-	-	-	-	505	-
End of 2019	-	-	-	-	-	523	-

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclo primarily because the quantities above include gas consumed in production operations. Quantities consumed in prod operations are not significant in the periods presented. The value of net production consumed in operations is not ref 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 Dec 2019, 2018 and 2017, respectively. These volumes are not included in the calculation of our Standardized Measure o 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/Mi upward revisions were primarily due to the Indonesia Corridor PSC term extension. Downward revisions in were due to changes in development timing for specific well locations from the unconventional plays of 207 price revisions of 125 Bcf, partially offset by upward revisions related to infill drilling and improved well pe of 219 Bcf.

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific locations from the unconventional plays and are more than offset by increases in planned well locations in th unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to d timing were partially offset by higher prices. Revisions in Alaska, Canada, Europe and our equity affiliates 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 acqu

- *Extensions and discoveries*: In 2019, extensions and discoveries in Lower 48 were due to planned developm specific well locations from the unconventional plays which more than offset the decreases in the revisions c 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 specific well locations from the unconventional plays. Extensions and discoveries in Canada, Europe and ou affiliates in Asia Pacific/Middle East were primarily driven by ongoing drilling successes in Montney, Norw APLNG, respectively.

  In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Perm Unconventional, Eagle Ford and Bakken.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Lower 48 sales were prim the disposition of our interest in Barnett. In 2017, Lower 48 sales were due to the disposition of our interests Juan Basin and Panhandle assets, while Canada sales were due to the disposition of a majority of our wester assets.

Years Ended December 31	Bitumen Millions of Barre Can
Developed and Undeveloped	
Consolidated operations	
End of 2016	1
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	
End of 2017	2
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	
End of 2018	2
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	
End of 2019	2
Equity affiliates	
End of 2016	1,0
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	(
Sales	(1,0
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	1,2
End of 2017	2
End of 2018	2
End of 2019	2

Years Ended December 31	Bitumen
	Millions of Barre
	Can
Developed	
Consolidated operations	
End of 2016	1
End of 2017	1
End of 2018	1
End of 2019	1
Equity affiliates	
End of 2016	3
End of 2017	
End of 2018	
End of 2019	
Undeveloped	
Consolidated operations	
End of 2016	
End of 2017	
End of 2018	
End of 2019	
Equity affiliates	
End of 2016	7
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 th 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 i 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	Afric
Developed and Undeveloped							
Consolidated operations							
End of 2016	1,294	1,570	2,864	393	528	444	241
Revisions	166	170	336	18	68	36	-
Improved recovery	6	-	6	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	41	378	419	97	-	7	-
Production	(77)	(144)	(221)	(37)	(79)	(81)	(8
Sales	-	(621)	(621)	(217)	-	-	-
End of 2017	1,430	1,353	2,783	254	517	406	233
Revisions	102	(161)	(59)	12	40	5	6
Improved recovery	2	-	2	-	-	-	-
Purchases	289	1	290	-	-	-	-
Extensions and discoveries	48	335	383	4	21	6	-
Production	(76)	(146)	(222)	(25)	(75)	(75)	(15
Sales	-	(70)	(70)	-	(38)	-	-
End of 2018	1,795	1,312	3,107	245	465	342	224
Revisions	44	(67)	(23)	36	48	19	26
Improved recovery	7	-	7	-	-	-	-
Purchases	-	2	2	-	-	-	-
Extensions and discoveries	26	368	394	38	-	11	-
Production	(93)	(165)	(258)	(23)	(68)	(74)	(16
Sales	-	(3)	(3)	-	(85)	-	-
End of 2019	1,779	1,447	3,226	296	360	298	234
Equity affiliates							
End of 2016	-	-	-	1,089	-	865	-
Revisions	-	-	-	-	-	18	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	31	-
Production	-	-	-	(23)	-	(69)	-
Sales	-	-	-	(1,066)	-	-	-
End of 2017	-	-	-	-	-	845	-
Revisions	-	-	-	-	-	46	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	60	-
Production	-	-	-	-	-	(71)	-
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	880	-
Revisions	-	-	-	-	-	(1)	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	42	-
Production	-	-	-	-	-	(73)	-
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	848	-
Total company							
End of 2016	1,294	1,570	2,864	1,482	528	1,309	241
End of 2017	1,430	1,353	2,783	254	517	1,251	233
End of 2018	1,795	1,312	3,107	245	465	1,222	224
End of 2019	1,779	1,447	3,226	296	360	1,146	234

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	Afric
Developed							
Consolidated operations							
End of 2016	1,203	1,165	2,368	391	365	309	241
End of 2017	1,319	682	2,001	158	372	281	233
End of 2018	1,617	681	2,298	160	382	244	221
End of 2019	1,582	666	2,248	197	275	236	218
Equity affiliates							
End of 2016	-	-	-	322	-	820	-
End of 2017	-	-	-	-	-	802	-
End of 2018	-	-	-	-	-	796	-
End of 2019	-	-	-	-	-	761	-
Undeveloped							
Consolidated operations							
End of 2016	91	405	496	2	163	135	-
End of 2017	111	671	782	96	145	125	-
End of 2018	178	631	809	85	83	98	3
End of 2019	197	781	978	99	85	62	16
Equity affiliates							
End of 2016	-	-	-	767	-	45	-
End of 2017	-	-	-	-	-	43	-
End of 2018	-	-	-	-	-	84	-
End of 2019	-	-	-	-	-	87	-

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six MCF of natural gas co
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 Undevelope Millions o Oi
End of 2018	
Transfers to proved developed	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Sales	
End of 2019	

Transfers to proved developed reserves were driven by the ongoing development of our assets. Approximately half o
transfers were from the development of our Lower 48 unconventional plays. The remainder of transfers were from d
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 Can
largely offset by upward revisions for infill drilling of 147 MMBOE primarily in Lower 48, Europe, Alaska and Afri

Extensions and discoveries were largely driven by an addition of 358 MMBOE in Lower 48 for the continued develo
unconventional plays. The remaining extensions and discoveries were driven by the continued development planned
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 Dece
2018. Costs incurred for the year ended December 31, 2019, relating to the development of PUDs were $4.6 billion.
portion costs incurred each year relates to development projects where the PUDs will be converted to proved develope
in future years.

At the end of 2019, more than 90 percent of total PUDs were under development or scheduled for development withi
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 h
convert to proved developed over time. Of our total PUDs at year-end 2019, 81 percent are in North America, and 9
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 f
tables. Non-oil and gas activities, such as pipeline and marine operations, LNG operations, crude oil and gas market
activities, and the profit element of transportation operations in which we have an ownership interest are excluded. A
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 r
interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a f
delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a
delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sa
hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used i
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 othe
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	Othe Area
Consolidated operations								
Sales	$ 4,883	6,356	11,239	709	3,207	3,032	919	-
Transfers	4	-	4	-	-	449	-	-
Transportation	(629)	-	(629)	-	-	(41)	-	-
Other revenues	61	78	139	86	1,785	12	101	326
Total revenues	4,319	6,434	10,753	795	4,992	3,452	1,020	326
Production costs excluding taxes	1,235	1,578	2,813	380	741	619	70	(8
Taxes other than income taxes	308	437	745	18	32	54	3	(2
Exploration expenses	97	430	527	32	69	80	5	33
Depreciation, depletion and amortization	700	2,804	3,504	230	842	1,172	37	-
Impairments	-	402	402	2	1	-	-	-
Other related expenses	(12)	116	104	(38)	(42)	58	22	10
Accretion	62	49	111	7	142	43	-	-
	1,929	618	2,547	164	3,207	1,426	883	293
Income tax provision (benefit)	444	147	591	(74)	591	458	833	7
Results of operations	$ 1,485	471	1,956	238	2,616	968	50	286
Equity affiliates								
Sales	$ -	-	-	-	-	599	-	-
Transfers	-	-	-	-	-	2,229	-	-
Transportation	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	31	-	-
Total revenues	-	-	-	-	-	2,859	-	-
Production costs excluding taxes	-	-	-	-	-	335	-	-
Taxes other than income taxes	-	-	-	-	-	820	-	-
Exploration expenses	-	-	-	-	-	-	-	-
Depreciation, depletion and amortization	-	-	-	-	-	579	-	-
Impairments	-	-	-	-	-	-	-	-
Other related expenses	-	-	-	-	-	11	-	-
Accretion	-	-	-	-	-	16	-	-
	-	-	-	-	-	1,098	-	-
Income tax provision (benefit)	-	-	-	-	-	170	-	-
Results of operations	$ -	-	-	-	-	928	-	-

Year Ended December 31, 2018		Millions of Dollars								
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	To
Consolidated operations										
Sales	$	4,816	6,573	11,389	582	4,449	3,177	950	-	20,5
Transfers		5	-	5	-	-	545	-	-	5
Transportation		(722)	-	(722)	-	-	(45)	-	-	(7
Other revenues		335	213	548	164	737	6	110	432	1,9
Total revenues		4,434	6,786	11,220	746	5,186	3,683	1,060	432	22,3
Production costs excluding taxes		964	1,533	2,497	417	856	646	62	2	4,4
Taxes other than income taxes		357	432	789	21	33	95	3	-	9
Exploration expenses		59	176	235	21	57	43	(4)	20	3
Depreciation, depletion and amortization		616	2,279	2,895	313	1,070	1,186	33	-	5,4
Impairments		1	64	65	9	(78)	14	-	-	
Other related expenses		16	63	79	56	(62)	(19)	1	(1)	
Accretion		56	51	107	7	178	39	-	-	3
		2,365	2,188	4,553	(98)	3,132	1,679	965	411	10,6
Income tax provision (benefit)		419	466	885	(114)	1,354	683	926	(8)	3,7
Results of operations	$	1,946	1,722	3,668	16	1,778	996	39	419	6,9
Equity affiliates										
Sales	$	-	-	-	-	-	758	-	-	7
Transfers		-	-	-	-	-	2,018	-	-	2,0
Transportation		-	-	-	-	-	-	-	-	
Other revenues		-	-	-	-	-	(6)	-	-	
Total revenues		-	-	-	-	-	2,770	-	-	2,7
Production costs excluding taxes		-	-	-	-	-	321	-	-	3
Taxes other than income taxes		-	-	-	-	-	804	-	-	8
Exploration expenses		-	-	-	-	-	-	-	-	
Depreciation, depletion and amortization		-	-	-	-	-	640	-	-	6
Impairments		-	-	-	-	-	-	-	-	
Other related expenses		-	-	-	-	-	(4)	-	-	
Accretion		-	-	-	-	-	15	-	-	
		-	-	-	-	-	994	-	-	9
Income tax provision (benefit)		-	-	-	-	-	103	-	-	1
Results of operations	$	-	-	-	-	-	891	-	-	8

Year Ended December 31, 2017	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Ot Ar
Consolidated operations								
Sales	$ 3,542	4,557	8,099	705	3,527	2,752	487	
Transfers	4	-	4	-	-	411	-	
Transportation costs	(706)	-	(706)	-	-	(80)	-	
Other revenues	14	28	42	2,158	68	11	48	3
Total revenues	2,854	4,585	7,439	2,863	3,595	3,094	535	3
Production costs excluding taxes	947	1,607	2,554	604	770	566	44	
Taxes other than income taxes	275	318	593	33	32	39	2	
Exploration expenses	83	584	667	22	45	97	61	
Depreciation, depletion and amortization	730	2,685	3,415	438	1,234	1,283	16	
Impairments	179	3,969	4,148	22	46	-	-	
Other related expenses	(7)	62	55	7	57	60	6	
Accretion	52	63	115	16	172	37	-	
	595	(4,703)	(4,108)	1,721	1,239	1,012	406	2
Income tax provision (benefit)	(669)	(2,401)	(3,070)	(651)	702	363	428	
Results of operations	$ 1,264	(2,302)	(1,038)	2,372	537	649	(22)	2
Equity affiliates								
Sales	$ -	-	-	528	-	563	-	
Transfers	-	-	-	-	-	1,398	-	
Transportation costs	-	-	-	-	-	-	-	
Other revenues	-	-	-	5	-	-	-	
Total revenues	-	-	-	533	-	1,961	-	
Production costs excluding taxes	-	-	-	174	-	363	-	
Taxes other than income taxes	-	-	-	7	-	604	-	
Exploration expenses	-	-	-	1	-	1,699	-	
Depreciation, depletion and amortization	-	-	-	150	-	617	-	
Impairments	-	-	-	-	-	1,717	-	
Other related expenses	-	-	-	4	-	22	-	
Accretion	-	-	-	2	-	11	-	
	-	-	-	195	-	(3,072)	-	(
Income tax provision (benefit)	-	-	-	26	-	(998)	-	
Results of operations	$ -	-	-	169	-	(2,074)	-	(

Statistics

Net Production	**2019**	2018	20
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**202**	171	1
Lower 48	**266**	229	1
United States	**468**	400	3
Canada	**1**	1	
Europe	**100**	113	1
Asia Pacific/Middle East	**85**	89	
Africa	**38**	36	
Total consolidated operations	**692**	639	5
Equity affiliates—Asia Pacific/Middle East	**13**	14	
Total company	**705**	653	5
*Greater Prudhoe Area (Alaska)**	***66***	*71*	
Natural Gas Liquids			
Consolidated operations			
Alaska	**15**	14	
Lower 48	**81**	69	
United States	**96**	83	
Canada	**-**	1	
Europe	**7**	8	
Asia Pacific/Middle East	**4**	3	
Total consolidated operations	**107**	95	1
Equity affiliates—Asia Pacific/Middle East	**8**	7	
Total company	**115**	102	1
*Greater Prudhoe Area (Alaska)**	***15***	*14*	
Bitumen			
Consolidated operations—Canada	**60**	66	
Equity affiliates—Canada			
Total company	**60**	66	1
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**7**	6	
Lower 48	**622**	596	8
United States	**629**	602	9
Canada	**9**	12	1
Europe	**447**	475	4
Asia Pacific/Middle East	**637**	626	6
Africa	**31**	28	
Total consolidated operations	**1,753**	1,743	2,2
Equity affiliates—Asia Pacific/Middle East	**1,052**	1,031	1,0
Total company	**2,805**	2,774	3,2
*Greater Prudhoe Area (Alaska)**	***4***	*5*	

**At year-end 2019, the Greater Prudhoe Area in Alaska contained more than 15% of total proved reserves.*

Average Sales Prices	2019	2018	20
Crude Oil Per Barrel			
Consolidated operations			
Alaska	$ **55.85**	60.23	42.
Lower 48	**55.30**	62.99	47.
United States	**55.54**	61.75	45.
Canada	**40.87**	48.73	43.
Europe	**65.12**	70.98	54.
Asia Pacific/Middle East	**65.02**	70.93	54.
Africa	**64.47**	69.83	55.
Total international	**64.85**	70.67	54.
Total consolidated operations	**58.51**	65.01	48.
Equity affiliates—Asia Pacific/Middle East	**61.32**	72.49	54.
Total operations	**58.57**	65.17	48.
Natural Gas Liquids Per Barrel			
Consolidated operations			
Lower 48	$ **16.83**	27.30	22.
United States	**16.85**	27.30	22.
Canada	**19.87**	43.70	21.
Europe	**29.37**	36.87	34.
Asia Pacific/Middle East	**37.85**	47.20	41.
Total international	**32.29**	40.00	30.
Total consolidated operations	**18.73**	29.03	24.
Equity affiliates—Asia Pacific/Middle East	**36.70**	45.69	38.
Total operations	**20.09**	30.48	25.
Bitumen Per Barrel			
Consolidated operations—Canada	$ **31.72**	22.29	21.
Equity affiliates—Canada			23.
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	$ **3.19**	2.48	2.
Lower 48	**2.12**	2.82	2.
United States	**2.12**	2.82	2.
Canada	**0.49**	1.00	1.
Europe	**4.92**	7.79	5.
Asia Pacific/Middle East	**5.73**	5.95	4.
Africa	**4.87**	4.84	3.
Total international	**5.35**	6.64	4.
Total consolidated operations	**4.19**	5.33	3.
Equity affiliates—Asia Pacific/Middle East	**6.29**	6.06	4.
Total operations	**4.99**	5.60	4.

Average sales prices for Alaska crude oil and Asia Pacific/Middle East natural gas above reflect a reduction for transportation costs in which 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	2
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**15.52**	14.20	14.
Lower 48		**9.59**	10.58	11.
United States		**11.52**	11.73	12.
Canada		**16.53**	16.32	16.
Europe		**11.22**	11.73	10.
Asia Pacific/Middle East		**8.74**	9.03	7.
Africa		**4.46**	4.14	5.
Total international		**10.26**	10.72	9.
Total consolidated operations		**10.99**	11.26	11.
Equity affiliates				
Canada				7.
Asia Pacific/Middle East		**4.68**	4.56	5.
Total equity affiliates		**4.68**	4.56	5.
Average Production Costs Per Barrel—Bitumen				
Consolidated operations—Canada	$	**13.74**	13.59	14.
Equity affiliates—Canada				18.
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**3.87**	5.26	4.
Lower 48		**2.65**	2.98	2.
United States		**3.05**	3.71	2.
Canada		**0.78**	0.82	0.
Europe		**0.48**	0.45	0.
Asia Pacific/Middle East		**0.76**	1.33	0.
Africa		**0.19**	0.20	0.
Total international		**0.60**	0.82	0.
Total consolidated operations		**2.03**	2.37	1.
Equity affiliates				
Canada				0.
Asia Pacific/Middle East		**11.46**	11.41	8.
Total equity affiliates		**11.46**	11.41	6.
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**8.80**	9.07	10.
Lower 48		**17.03**	15.73	18.
United States		**14.35**	13.60	16.
Canada		**10.00**	12.25	11.
Europe		**12.75**	14.66	16.
Asia Pacific/Middle East		**16.55**	16.58	16.
Africa		**2.36**	2.21	2.
Total international		**12.99**	14.06	14.
Total consolidated operations		**13.78**	13.82	15.
Equity affiliates				
Canada				6.
Asia Pacific/Middle East		**8.09**	9.09	8.
Total equity affiliates		**8.09**	9.09	8.

**Includes bitumen.*

Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wel 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 relatin 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	20
Exploratory						
Consolidated operations						
Alaska	**7**	6	-	**-**	-	
Lower 48	**35**	45	13	**6**	1	
United States	**42**	51	13	**6**	1	
Canada	**-**	2	13	**-**	-	
Europe	**1**	*	*	**1**	*	
Asia Pacific/Middle East	**1**	2	1	**1**	-	
Africa	**-**	-	-	**-**	*	
Other areas	**-**	-	-	**-**	-	
Total consolidated operations	**44**	55	27	**8**	1	
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	In Progress		Productive			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	N[e]
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[illegible]
Europe	19	1	469	79	55	2[illegible]
Asia Pacific/Middle East	12	6	302	143	56	28[illegible]
Africa	13	2	840	137	7	1[illegible]
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	N[et]
Consolidated operations				
Alaska	651	467	1,331	1,32[illegible]
Lower 48	2,569	2,012	10,337	8,39[illegible]
United States	3,220	2,479	11,668	9,71[illegible]
Canada	206	126	3,270	1,79[illegible]
Europe	430	50	2,102	61[illegible]
Asia Pacific/Middle East	1,538	721	9,910	5,73[illegible]
Africa	358	58	12,545	2,04[illegible]
Other areas	-	-	1,400	74[illegible]
Total consolidated operations	5,752	3,434	40,895	20,65[illegible]
Equity affiliates				
Asia Pacific/Middle East	933	229	3,723	84[illegible]
Total equity affiliates	933	229	3,723	84[illegible]

Costs Incurred

Year Ended December 31		Millions of Dollars							
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas
2019									
Consolidated operations									
Unproved property acquisition	$	101	45	146	14	-	-	-	197
Proved property acquisition		1	116	117	-	-	115	-	-
		102	161	263	14	-	115	-	197
Exploration		281	390	671	200	119	66	8	39
Development		1,125	3,028	4,153	215	625	486	22	-
	$	1,508	3,579	5,087	429	744	667	30	236
Equity affiliates									
Unproved property acquisition	$	-	-	-	-	-	62	-	-
Proved property acquisition		-	-	-	-	-	-	-	-
		-	-	-	-	-	62	-	-
Exploration		-	-	-	-	-	23	-	-
Development		-	-	-	-	-	171	-	-
	$	-	-	-	-	-	256	-	-
2018									
Consolidated operations									
Unproved property acquisition	$	119	126	245	126	-	-	-	-
Proved property acquisition		2,227	16	2,243	6	-	-	-	-
		2,346	142	2,488	132	-	-	-	-
Exploration		203	500	703	90	65	82	(6)	41
Development		718	2,715	3,433	301	703	773	16	-
	$	3,267	3,357	6,624	523	768	855	10	41
Equity affiliates									
Unproved property acquisition	$	-	-	-	-	-	-	-	-
Proved property acquisition		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
Exploration		-	-	-	-	-	22	-	-
Development		-	-	-	-	-	206	-	-
	$	-	-	-	-	-	228	-	-
2017									
Consolidated operations									
Unproved property acquisition	$	18	267	285	76	-	15	-	-
Proved property acquisition		-	35	35	-	-	-	-	-
		18	302	320	76	-	15	-	-
Exploration		74	399	473	56	52	139	61	42
Development		736	1,559	2,295	102	784	388	10	-
	$	828	2,260	3,088	234	836	542	71	42
Equity affiliates									
Unproved property acquisition	$	-	-	-	-	-	-	-	-
Proved property acquisition		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
Exploration		-	-	-	6	-	38	-	-
Development		-	-	-	150	-	403	-	-
	$	-	-	-	156	-	441	-	-

Capitalized Costs

At December 31	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas
2019								
Consolidated operations								
Proved property	$ 20,957	37,491	58,448	6,673	14,113	14,566	924	-
Unproved property	1,429	1,055	2,484	1,149	87	501	123	290
	22,386	38,546	60,932	7,822	14,200	15,067	1,047	290
Accumulated depreciation, depletion and amortization	9,419	26,294	35,713	2,050	9,017	10,253	379	9
	$ 12,967	12,252	25,219	5,772	5,183	4,814	668	281
Equity affiliates								
Proved property	$ -	-	-	-	-	9,996	-	-
Unproved property	-	-	-	-	-	2,223	-	-
	-	-	-	-	-	12,219	-	-
Accumulated depreciation, depletion and amortization	-	-	-	-	-	6,390	-	-
	$ -	-	-	-	-	5,829	-	-
2018								
Consolidated operations								
Proved property	$ 20,154	35,269	55,423	5,946	23,520	14,866	902	-
Unproved property	1,184	1,125	2,309	1,083	188	874	119	89
	21,338	36,394	57,732	7,029	23,708	15,740	1,021	89
Accumulated depreciation, depletion and amortization	9,055	23,999	33,054	1,692	16,591	9,974	342	9
	$ 12,283	12,395	24,678	5,337	7,117	5,766	679	80
Equity affiliates								
Proved property	$ -	-	-	-	-	9,990	-	-
Unproved property	-	-	-	-	-	2,162	-	-
	-	-	-	-	-	12,152	-	-
Accumulated depreciation, depletion and amortization	-	-	-	-	-	5,960	-	-
	$ -	-	-	-	-	6,192	-	-

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantit

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end ec conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time a becomes available. Probable or possible reserves, which may become proved in the future, were not considered. Th calculations also require assumptions as to the timing of future production of proved reserves and the timing and amo future development costs, including dismantlement, and future production costs, including taxes other than income ta

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas prop 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
2019							
Consolidated operations							
Future cash inflows	$ 70,341	53,400	123,741	8,244	16,919	13,084	15,582
Less:							
Future production costs	40,464	22,194	62,658	4,525	5,843	5,162	1,314
Future development costs	9,721	14,083	23,804	577	4,143	2,179	484
Future income tax provisions	3,904	2,793	6,697	-	4,201	1,931	12,747
Future net cash flows	16,252	14,330	30,582	3,142	2,732	3,812	1,037
10 percent annual discount	6,571	4,311	10,882	1,198	558	835	460
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	2,977	577
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	31,671	-
Less:							
Future production costs	-	-	-	-	-	16,157	-
Future development costs	-	-	-	-	-	1,218	-
Future income tax provisions	-	-	-	-	-	3,086	-
Future net cash flows	-	-	-	-	-	11,210	-
10 percent annual discount	-	-	-	-	-	4,040	-
Discounted future net cash flows	$ -	-	-	-	-	7,170	-
Total company							
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	10,147	577

	Millions of Dollars						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Afri
2018							
Consolidated operations							
Future cash inflows	$ 82,072	56,922	138,994	6,039	26,989	16,368	16,43
Less:							
Future production costs	42,755	21,363	64,118	4,099	8,567	5,705	1,33
Future development costs	10,053	12,136	22,189	606	7,608	1,995	50
Future income tax provisions	5,538	4,418	9,956	-	7,102	2,873	13,49
Future net cash flows	23,726	19,005	42,731	1,334	3,712	5,795	1,09
10 percent annual discount	10,349	6,461	16,810	426	371	1,132	49
Discounted future net cash flows	$ 13,377	12,544	25,921	908	3,341	4,663	60
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	33,606	
Less:							
Future production costs	-	-	-	-	-	16,449	
Future development costs	-	-	-	-	-	1,228	
Future income tax provisions	-	-	-	-	-	3,147	
Future net cash flows	-	-	-	-	-	12,782	
10 percent annual discount	-	-	-	-	-	4,853	
Discounted future net cash flows	$ -	-	-	-	-	7,929	
Total company							
Discounted future net cash flows	$ 13,377	12,544	25,921	908	3,341	12,592	60

	Millions of Dollars						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa
2017							
Consolidated operations							
Future cash inflows	$ 44,969	44,556	89,525	5,479	23,137	15,207	13,181
Less:							
Future production costs	29,524	18,947	48,471	4,417	8,128	5,398	1,401
Future development costs	7,255	10,881	18,136	696	8,758	2,511	537
Future income tax provisions	53	2,375	2,428	-	3,333	2,459	10,356
Future net cash flows	8,137	12,353	20,490	366	2,918	4,839	887
10 percent annual discount	2,712	4,358	7,070	78	289	1,032	422
Discounted future net cash flows	$ 5,425	7,995	13,420	288	2,629	3,807	465
Equity affiliates							
Future cash inflows	$ -	-	-	-	-	23,222	-
Less:							
Future production costs	-	-	-	-	-	12,984	-
Future development costs	-	-	-	-	-	1,444	-
Future income tax provisions	-	-	-	-	-	2,083	-
Future net cash flows	-	-	-	-	-	6,711	-
10 percent annual discount	-	-	-	-	-	2,316	-
Discounted future net cash flows	$ -	-	-	-	-	4,395	-
Total company							
Discounted future net cash flows	$ 5,425	7,995	13,420	288	2,629	8,202	465

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
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
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)
Net change in prices and production costs		**(13,538)**	25,391	19,310	**(422)**	4,559	2,750	**(13,960)**	29,950
Extensions, discoveries and improved recovery, less estimated future costs		**2,985**	4,574	1,445	**260**	382	(4)	**3,245**	4,956
Development costs for the year		**5,333**	5,197	3,653	**239**	271	426	**5,572**	5,468
Changes in estimated future development costs		**559**	(1,141)	1,225	**(21)**	14	(64)	**538**	(1,127)
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)
Revisions of previous quantity estimates		**2,099**	(365)	2,300	**69**	62	(648)	**2,168**	(303)
Accretion of discount		**5,144**	3,055	1,313	**869**	485	413	**6,013**	3,540
Net change in income taxes		**4,767**	(8,479)	(6,089)	**(80)**	(588)	(288)	**4,687**	(9,067)
Total changes		**(8,062)**	14,825	12,458	**(759)**	3,534	458	**(8,821)**	18,359
Discounted future net cash flows at year end	$	**27,372**	35,434	20,609	**7,170**	7,929	4,395	**34,542**	43,363

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by 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 calculate production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales pr future estimated costs, discounted at 10 percent.
- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted 10 percent.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production 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 Comm
	Sales and Other Operating Revenues	Income (Loss) Before Income Taxes	Net Income (Loss)	Net Income (Loss) Attributable to ConocoPhillips	Net Income (I Attributab to ConocoPhi Basic
2019					
First	**$ 9,150**	**2,687**	**1,846**	**1,833**	**1.61**
Second	**7,953**	**2,058**	**1,597**	**1,580**	**1.40**
Third	**7,756**	**3,493**	**3,071**	**3,056**	**2.76**
Fourth	**7,708**	**1,286**	**743**	**720**	**0.66**
2018					
First	$ 8,798	1,776	900	888	0.75
Second	8,504	2,619	1,654	1,640	1.40
Third	9,449	2,906	1,873	1,861	1.60
Fourth	9,666	2,672	1,878	1,868	1.62

For additional information on the commodity price environment, see the Business Environment and Executive Overview section of Management's Discus 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 Resourc 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 Compa 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 informatio 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 repayme 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 capi 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 subsidiarie 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		Millions of Dollars Year Ended December 31, 2019 ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments
Revenues and Other Income						
Sales and other operating revenues	$	-	14,510	-	18,057	-
Equity in earnings of affiliates		7,419	5,281	1,610	775	(14,306)
Gain (loss) on dispositions		-	2,786	-	(820)	-
Other income		1	875	5	477	-
Intercompany revenues		-	113	40	5,542	(5,695)
Total Revenues and Other Income		7,420	23,565	1,655	24,031	(20,001)
Costs and Expenses						
Purchased commodities		-	12,838	-	4,038	(5,034)
Production and operating expenses		1	1,380	1	4,345	(405)
Selling, general and administrative expenses		9	421	-	131	(5)
Exploration expenses		-	422	-	321	-
Depreciation, depletion and amortization		-	596	-	5,494	-
Impairments		-	157	-	248	-
Taxes other than income taxes		-	139	-	814	-
Accretion on discounted liabilities		-	16	-	310	-
Interest and debt expense		283	544	133	69	(251)
Foreign currency transaction losses		-	21	-	45	-
Other expenses		-	60	-	5	-
Total Costs and Expenses		293	16,594	134	15,820	(5,695)
Income before income taxes		7,127	6,971	1,521	8,211	(14,306)
Income tax provision (benefit)		(62)	(448)	(46)	2,823	-
Net income		7,189	7,419	1,567	5,388	(14,306)
Less: net income attributable to noncontrolling interests		-	-	-	(68)	-
Net Income Attributable to ConocoPhillips	$	7,189	7,419	1,567	5,320	(14,306)
Comprehensive Income Attributable to ConocoPhillips	$	7,935	8,165	1,873	6,058	(16,096)

Income Statement		Year Ended December 31, 2018				
Revenues and Other Income						
Sales and other operating revenues	$	-	16,113	-	20,304	-
Equity in earnings of affiliates		6,503	8,142	1,953	1,072	(16,596)
Gain on dispositions		-	239	-	824	-
Other income (loss)		-	(384)	-	557	-
Intercompany revenues		35	162	43	5,627	(5,867)
Total Revenues and Other Income		6,538	24,272	1,996	28,384	(22,463)
Costs and Expenses						
Purchased commodities		-	14,591	-	5,131	(5,428)
Production and operating expenses		-	1,023	4	4,245	(59)
Selling, general and administrative expenses		8	289	-	109	(5)
Exploration expenses		-	170	-	199	-
Depreciation, depletion and amortization		-	584	-	5,372	-
Impairments		-	(10)	-	37	-
Taxes other than income taxes		-	143	-	905	-
Accretion on discounted liabilities		-	17	-	336	-
Interest and debt expense		295	613	46	156	(375)
Foreign currency transaction (gains) losses		46	(12)	116	(167)	-
Other expenses		-	349	6	20	-
Total Costs and Expenses		349	17,757	172	16,343	(5,867)
Income before income taxes		6,189	6,515	1,824	12,041	(16,596)
Income tax provision (benefit)		(68)	12	(41)	3,765	-
Net income		6,257	6,503	1,865	8,276	(16,596)
Less: net income attributable to noncontrolling interests		-	-	-	(48)	-
Net Income Attributable to ConocoPhillips	$	6,257	6,503	1,865	8,228	(16,596)
Comprehensive Income Attributable to ConocoPhillips	$	5,654	5,900	1,364	7,961	(15,225)

See Notes to Consolidated Financial Statements.

Income Statement		ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments
		Millions of Dollars Year Ended December 31, 2017				
Revenues and Other Income						
Sales and other operating revenues	$	-	12,433	-	16,673	-
Equity in earnings (losses) of affiliates		(454)	2,047	886	770	(2,477)
Gain on dispositions		-	916	-	1,261	-
Other income		2	35	-	492	-
Intercompany revenues		48	291	13	3,369	(3,721)
Total Revenues and Other Income		(404)	15,722	899	22,565	(6,198)
Costs and Expenses						
Purchased commodities		-	11,145	-	4,580	(3,250)
Production and operating expenses		-	813	-	4,366	(17)
Selling, general and administrative expenses		9	342	-	82	(6)
Exploration expenses		-	542	-	392	-
Depreciation, depletion and amortization		-	855	-	5,990	-
Impairments		-	1,159	-	5,442	-
Taxes other than income taxes		-	140	1	668	-
Accretion on discounted liabilities		-	32	-	330	-
Interest and debt expense		420	664	52	410	(448)
Foreign currency transaction (gains) losses		(43)	11	(137)	204	-
Other expenses		267	190	-	(6)	-
Total Costs and Expenses		653	15,893	(84)	22,458	(3,721)
Income (Loss) before income taxes		(1,057)	(171)	983	107	(2,477)
Income tax provision (benefit)		(202)	283	(337)	(1,566)	-
Net income (loss)		(855)	(454)	1,320	1,673	(2,477)
Less: net income attributable to noncontrolling interests		-	-	-	(62)	-
Net Income (Loss) Attributable to ConocoPhillips	$	(855)	(454)	1,320	1,611	(2,477)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$	(180)	221	1,672	2,275	(4,168)

See Notes to Consolidated Financial Statements.

Balance Sheet	Millions of Dollars At December 31, 2019 ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments
Assets					
Cash and cash equivalents	$ -	3,439	-	1,649	-
Short-term investments	-	2,670	-	358	-
Accounts and notes receivable	5	2,088	2	3,881	(2,575)
Investment in Cenovus Energy	-	2,111	-	-	-
Inventories	-	168	-	858	-
Prepaid expenses and other current assets	1	352	-	1,906	-
Total Current Assets	6	10,828	2	8,652	(2,575)
Investments, loans and long-term receivables*	34,076	44,969	11,662	15,612	(97,413)
Net properties, plants and equipment	-	3,552	-	38,717	-
Other assets	3	765	253	2,210	(805)
Total Assets	$ 34,085	60,114	11,917	65,191	(100,793)
Liabilities and Stockholders' Equity					
Accounts payable	$ -	2,670	21	3,084	(2,575)
Short-term debt	(3)	4	13	91	-
Accrued income and other taxes	-	79	-	951	-
Employee benefit obligations	-	508	-	155	-
Other accruals	84	408	35	1,518	-
Total Current Liabilities	81	3,669	69	5,799	(2,575)
Long-term debt	3,794	6,670	2,129	2,197	-
Asset retirement obligations and accrued environmental costs	-	322	-	5,030	-
Deferred income taxes	-	-	-	5,438	(804)
Employee benefit obligations	-	1,329	-	452	-
Other liabilities and deferred credits*	1,787	7,514	826	9,271	(17,534)
Total Liabilities	5,662	19,504	3,024	28,187	(20,913)
Retained earnings	33,184	21,898	2,164	10,481	(27,985)
Other common stockholders' equity	(4,761)	18,712	6,729	26,454	(51,895)
Noncontrolling interests	-	-	-	69	-
Total Liabilities and Stockholders' Equity	$ 34,085	60,114	11,917	65,191	(100,793)

Balance Sheet	At December 31, 2018 ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments
Assets					
Cash and cash equivalents	$ -	1,428	-	4,487	-
Short-term investments	-	-	-	248	-
Accounts and notes receivable	28	5,646	78	6,707	(8,392)
Investment in Cenovus Energy	-	1,462	-	-	-
Inventories	-	184	-	823	-
Prepaid expenses and other current assets	1	267	-	307	-
Total Current Assets	29	8,987	78	12,572	(8,392)
Investments, loans and long-term receivables*	29,942	47,062	15,199	16,926	(99,465)
Net properties, plants and equipment	-	4,367	-	41,796	(465)
Other assets	4	642	227	1,269	(798)
Total Assets	$ 29,975	61,058	15,504	72,563	(109,120)
Liabilities and Stockholders' Equity					
Accounts payable	$ -	5,098	76	7,113	(8,392)
Short-term debt	(3)	12	13	99	(9)
Accrued income and other taxes	-	85	-	1,235	-
Employee benefit obligations	-	638	-	171	-
Other accruals	85	587	35	552	-
Total Current Liabilities	82	6,420	124	9,170	(8,401)
Long-term debt	3,791	7,151	2,143	2,249	(478)
Asset retirement obligations and accrued environmental costs	-	415	-	7,273	-
Deferred income taxes	-	-	-	5,819	(798)
Employee benefit obligations	-	1,340	-	424	-
Other liabilities and deferred credits*	725	9,277	839	8,126	(17,775)
Total Liabilities	4,598	24,603	3,106	33,061	(27,452)
Retained earnings	27,512	18,511	1,113	9,764	(22,890)
Other common stockholders' equity	(2,135)	17,944	11,285	29,613	(58,778)
Noncontrolling interests	-	-	-	125	-
Total Liabilities and Stockholders' Equity	$ 29,975	61,058	15,504	72,563	(109,120)

**Includes intercompany loans.*
See Notes to Consolidated Financial Statements.

Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments
	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)
Cash Flows From Investing Activities					
Capital expenditures and investments	-	(2,517)	-	(5,714)	1,595
Working capital changes associated with investing activities	-	37	-	(140)	-
Proceeds from asset dispositions	2,374	7,047	769	1,055	(8,233)
Net purchases of investments	-	(2,803)	-	(107)	-
Long-term advances/loans—related parties	-	(812)	-	-	812
Collection of advances/loans—related parties	-	141	-	147	(161)
Intercompany cash management	1,060	(2,849)	1,402	387	-
Other	-	(149)	-	41	-
Net Cash Provided by (Used in) Investing Activities	3,434	(1,905)	2,171	(4,331)	(5,987)
Cash Flows From Financing Activities					
Issuance of debt	-	-	-	812	(812)
Repayment of debt	-	(21)	-	(220)	161
Issuance of company common stock	105	-	-	-	(135)
Repurchase of company common stock	(3,500)	-	-	-	-
Dividends paid	(1,500)	(4,034)	(454)	(7,097)	11,585
Other	4	-	(4,924)	(1,736)	6,537
Net Cash Used in Financing Activities	(4,891)	(4,055)	(5,378)	(8,241)	17,336
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	-	(11)	-	(35)	-
Net Change in Cash, Cash Equivalents and Restricted Cash	-	2,015	-	(2,804)	-
Cash, cash equivalents and restricted cash at beginning of period	-	1,428	-	4,723	-
Cash, Cash Equivalents and Restricted Cash at End of Period	$ -	3,443	-	1,919	-

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)
Cash Flows From Investing Activities					
Capital expenditures and investments	-	(980)	(603)	(5,777)	610
Working capital changes associated with investing activities	-	(110)	-	42	-
Proceeds from asset dispositions	3,457	666	1,926	705	(5,672)
Net sales of short-term investments	-	-	-	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)
Intercompany cash management	(803)	3,504	(2,150)	(551)	-
Other	-	151	-	3	-
Net Cash Provided by (Used in) Investing Activities	3,243	6,537	(788)	(3,839)	(8,996)
Cash Flows From Financing Activities					
Issuance of debt	-	10	-	299	(309)
Repayment of debt	-	(4,865)	(53)	(4,320)	4,243
Issuance of company common stock	254	-	-	-	(133)
Repurchase of company common stock	(2,999)	-	-	-	-
Dividends paid	(1,363)	(1,043)	-	(6,057)	7,100
Other	5	(3,468)	-	(1,670)	5,010
Net Cash Used in Financing Activities	(4,103)	(9,366)	(53)	(11,748)	15,911
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	-	4	-	(121)	-
Net Change in Cash, Cash Equivalents and Restricted Cash	-	1,194	(3)	(1,576)	-
Cash, cash equivalents and restricted cash at beginning of period	-	234	3	6,299	-
Cash, Cash Equivalents and Restricted Cash at End of Period	$ -	1,428	-	4,723	-

**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 Con*

Statement of Cash Flows	Millions of Dollars Year Ended December 31, 2017 ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments
Cash Flows From Operating Activities					
Net Cash Provided by Operating Activities	$ 71	1,183	2,971	5,904	(3,052)
Cash Flows From Investing Activities					
Capital expenditures and investments	-	(1,663)	(4,351)	(3,795)	5,218
Working capital changes associated with investing activities	-	194	-	(62)	-
Proceeds from asset dispositions	7,765	11,146	12,178	12,796	(30,025)
Net purchases of short-term investments	-	-	-	(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)
Intercompany cash management	1,151	101	(1,341)	89	-
Other	-	(8)	-	44	-
Net Cash Provided by Investing Activities	9,574	11,083	6,810	9,458	(29,163)
Cash Flows From Financing Activities					
Issuance of debt	-	20	-	279	(299)
Repayment of debt	(5,459)	(4,411)	-	(2,661)	4,655
Issuance of company common stock	115	-	-	-	(178)
Repurchase of company common stock	(3,000)	-	-	-	-
Dividends paid	(1,305)	(235)	-	(2,995)	3,230
Other	4	(7,765)	(9,781)	(7,377)	24,807
Net Cash Used in Financing Activities	(9,645)	(12,391)	(9,781)	(12,754)	32,215
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	1	(2)	233	-
Net Change in Cash and Cash Equivalents	-	(124)	(2)	2,841	-
Cash and cash equivalents at beginning of period	-	358	5	3,247	-
Cash and Cash Equivalents at End of Period	$ -	234	3	6,088	-

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 Commissi 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 requi 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 th evaluation, our Chairman and Chief Executive Officer and our Executive Vice President and Chief Financia Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 201

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of t 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 o 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 c 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 th "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 appeari 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 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 pa of this annual report.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

	Millions of Dollars				
Description	Balance at January 1	Charged to Expense	Other(a)	Deductions	Balance December
2019					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 25**	**5**	**-**	**(17)(b)**	**1**
Deferred tax asset valuation allowance	**3,040**	**7,376**	**(26)**	**(176)**	**10,21**
Included in other liabilities:					
Restructuring accruals	**48**	**(1)**	**-**	**(24)(c)**	**2**
2018					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 4	23	-	(2)(b)	2
Deferred tax asset valuation allowance	1,254	2,067	(8)	(273)	3,04
Included in other liabilities:					
Restructuring accruals	53	70	(2)	(73)(c)	4
2017					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 5	2	-	(3)(b)	
Deferred tax asset valuation allowance	675	560	19	-	1,25
Included in other liabilities:					
Restructuring accruals	80	65	1	(93)(c)	5

(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 deferre 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 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 Exhib 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 referen 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, 20 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 end December 31, 2005; File No. 001-32395).
10.9	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference 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- 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 Exhi 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 20 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 end 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 t 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 Repor 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 Repor 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 Pla 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 Annu 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 referen 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 end 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 referen 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 referen 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, 20 (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, date 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. to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 201 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 Progra 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 Quarte 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 Sha Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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 t the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File N 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 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; F No. 001-32395).
10.25.18	Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as par of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by referen 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 Progr 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 referen 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 3(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- 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 For 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 Quarter

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 Quarterl 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 Optior Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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 referen 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 Progr 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 Sto Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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 Incentiv Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.12 t the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File N 001-32395).
10.26.12	Form of Key Employee Award Terms and Conditions for eligible employees on the Canada payro 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 1 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 Sto Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhilli 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 U 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 1 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 Sto 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 Exhib 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 201 File No. 001-32395).
10.29	Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benef 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 Exhi 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 20 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 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 (incorpora 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. to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 201 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 Exhibi 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 3 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 Exchang 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 ha 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

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2018

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

Form 10-K

(Mark One)

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

For the fiscal year ended **December 31, 2018**

OR

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

For the transition period from ________________ to ________________
Commission file 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	Name of each exchange on which registered
Common Stock, $.01 Par Value	New York Stock Exchange
7% Debentures due 2029	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 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]

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 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $69.62, was $80.9 billion.

The registrant had 1,134,404,094 shares of common stock outstanding at January 31, 2019.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 14, 2019 (Part III)

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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 20 and “CAUTIONARY STATEMENT FOR THE PURPOSES OF THE ‘SAFE HARBOR’ PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995,” beginning on page 76.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is the world’s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 16 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; lower-risk conventional assets in North America, Europe, Asia and Australia; liquefied natural gas (LNG) developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2018, we employed approximately 10,800 people worldwide and had total assets of $70 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.

In April 2012, ConocoPhillips completed the separation of the downstream business into an independent, publicly traded energy company, Phillips 66.

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 natural gas liquids on a worldwide basis. At December 31, 2018, our operations were producing in the United States, Norway, the United Kingdom, 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, natural gas liquids, natural gas and bitumen reserves.
- Net production of crude oil, natural gas liquids, natural gas and bitumen.
- Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.

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- Average production costs per barrel of oil equivalent (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 thousand cubic feet (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	**2018**	2017	2016
Crude oil			
Consolidated operations	**2,533**	2,322	2,047
Equity affiliates	**78**	83	88
Total Crude Oil	**2,611**	2,405	2,135
Natural gas liquids			
Consolidated operations	**349**	354	457
Equity affiliates	**42**	45	47
Total Natural Gas Liquids	**391**	399	504
Natural gas			
Consolidated operations	**1,265**	1,267	1,807
Equity affiliates	**760**	717	730
Total Natural Gas	**2,025**	1,984	2,537
Bitumen			
Consolidated operations	**236**	250	159
Equity affiliates	**-**	-	1,089
Total Bitumen	**236**	250	1,248
Total consolidated operations	**4,383**	4,193	4,470
Total equity affiliates	**880**	845	1,954
Total company	**5,263**	5,038	6,424

Total production, including Libya, of 1,283 thousand barrels of oil equivalent per day (MBOED) decreased 7 percent in 2018 compared with 2017. The decrease in total average production primarily resulted from noncore asset dispositions, including the dispositions 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, and our interest in the San Juan Basin in the Lower 48 in 2017; normal field decline; and higher unplanned downtime, including a third-party pipeline outage in Malaysia in 2018. The decrease in production was partly offset by growth from the Big 3 Unconventionals —Eagle Ford, Bakken and Delaware, development programs primarily in Europe and Alaska, and rampup of major projects in Asia Pacific.

Production excluding Libya was 1,242 MBOED in 2018 compared with 1,356 MBOED in 2017. The volume from closed dispositions was approximately 200 MBOED in 2017 and 15 MBOED in 2018. The volume from acquisitions was less than 10 MBOED in 2018. Our underlying production, which excludes the full-year impact of acquisitions, dispositions, and Libya, increased over 5 percent in 2018 compared with 2017.

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Our worldwide annual average realized price was $53.88 per BOE in 2018, an increase of 37 percent compared with $39.19 per BOE in 2017, reflecting stronger marker prices as well as a shift in our portfolio toward a higher mix of crude oil and less of bitumen and natural gas. Our worldwide annual average crude oil price increased 31 percent in 2018, from $51.96 per barrel in 2017 to $68.13 per barrel in 2018. Additionally, our worldwide annual average natural gas liquids prices increased 21 percent, from $25.22 per barrel in 2017 to $30.48 per barrel in 2018. Our worldwide annual average natural gas price increased 39 percent, from $4.07 per MCF in 2017 to $5.65 per MCF in 2018. Average annual bitumen prices decreased 2 percent, from $22.66 per barrel in 2017 to $22.29 per barrel in 2018.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids. 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 1.25 million net undeveloped acres at year-end 2018. Alaska operations contributed 23 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

			2018		
	Interest	Operator	Liquids MBD *	Natural Gas MMCFD **	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1 %	BP	85	5	86
Greater Kuparuk Area***	91.4-94.7	ConocoPhillips	56	1	56
Western North Slope***	100.0	ConocoPhillips	44	-	44
Total Alaska			185	6	186

** Thousands of barrels per day.*
***Millions of cubic feet per day.*
**** Interest at December 31, 2018. See "Acquisitions" below for additional information.*

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 natural gas liquids 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.

We completed a transaction in the fourth quarter of 2018 which increased our interest in the Greater Kuparuk Area by 39.2 percent. Further discussion of the transaction is included in the "Acquisitions" section below.

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 2018, 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, which is currently planned to have 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 we expect first oil from GMT-2 in 2021.

We completed a transaction in the second quarter of 2018 to increase our interest in the Western North Slope from 78 percent to 100 percent. Further discussion of the transaction is included in the "Acquisitions" section below.

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 front-end engineering and design (pre-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 progressing the project on its own and signed several Memorandums of Understanding with various potential LNG buyers in Asia. AGDC has also signed a Joint Development Agreement with Sinopec, CIC Capital and Bank of China, which was recently extended to June 30, 2019. In early January 2019, recently elected Governor Dunleavy appointed new members to AGDC's board of directors who replaced AGDC's president with an interim president. The Dunleavy administration has indicated they are interested in participation in the project by ConocoPhillips, ExxonMobil and BP. We remain willing to make our equity gas available for sale to the project at mutually agreed, commercially reasonable terms.

Exploration
Appraisal of the Willow Discovery, located in the northeast portion of the National Petroleum Reserve-Alaska, continued throughout 2018 with three appraisal wells. Additionally, the West Willow-1 exploration well, drilled in 2018, resulted in an oil discovery. In 2019, we will continue appraisal of the Willow and West Willow discoveries.

The Putu 2/2A and Stony Hill 1 wells were drilled in 2018 on state and federal leases, resulting in oil discoveries. In late 2018, we commenced appraisal of the Putu Discovery with a long reach well from existing Alpine CD4 infrastructure.

The Cairn 2S-315 Well was drilled in late 2018 from the 2S drill site on state leases in the Kuparuk River Unit. A flow test will commence in the first quarter of 2019.

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

We were successful in the federal lease sale on the North Slope in the fourth quarter of 2018, where we were the high bidder on five tracts for a total of approximately 48,000 net acres.

Acquisitions
During the second quarter of 2018, we obtained regulatory approvals and completed a transaction we entered into with Anadarko Petroleum Corporation to acquire its 22 percent nonoperated interest in the Western North Slope of Alaska, as well as its interest in the Alpine Transportation Pipeline. In 2018, our Alaska segment net production included 7 MBOED associated with the additional interest acquired.

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During the fourth quarter of 2018, we completed a transaction with BP to acquire their 39.2 percent nonoperated interest in the Greater Kuparuk Area, including their 38 percent interest in the Kuparuk Transportation Company in Alaska (Kuparuk Assets), and to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. In 2018, our Alaska segment net production included 1 MBOED associated with the additional interest acquired in the Greater Kuparuk Area.

See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

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 United States.

LOWER 48

The Lower 48 segment consists of operations located in the contiguous United States and the Gulf of Mexico. The Lower 48 business is organized within two regions covering the Gulf Coast and Great Plains. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost of supply plays. We disposed of several noncore assets within the Lower 48 in 2018, including our interests in the Barnett and certain conventional assets in the Permian Basin. In 2017, we disposed of our interest in the San Juan Basin. We hold 10.3 million net onshore and offshore acres in the Lower 48. In 2018, the Lower 48 contributed 36 percent of our worldwide liquids production and 21 percent of our natural gas production.

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various %	Various	151	212	186
Gulf of Mexico	Various	Various	12	9	14
Gulf Coast—Other	Various	Various	3	8	4
Total Gulf Coast			166	229	204
Bakken	Various	Various	72	72	84
Permian	Various	Various	46	126	66
Anadarko Basin	Various	Various	4	59	14
Wyoming/Uinta	Various	Various	-	78	13
Barnett	*	Various	3	25	8
Niobrara	Various	Various	7	7	8
Total Great Plains			132	367	193
Total U.S. Lower 48			298	596	397

**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 1.6 million net acres in the following areas:

- 620,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 225,000 net acres in central Louisiana.
- 200,000 net acres in the Eagle Ford, located in South Texas.
- 145,000 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 98,000 net acres in the Niobrara, located in northeastern Colorado.
- 340,000 net acres in other areas with unconventional potential.

The majority of our 2018 onshore production originated from the Big 3—Eagle Ford, Bakken and the Delaware in the Permian Basin. Onshore activities in 2018 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 2018 included the following:

- Eagle Ford—The Eagle Ford continued full-field development in 2018. We operated seven rigs on average in 2018, resulting in 166 operated wells drilled and 149 operated wells brought online. Production increased 40 percent in 2018 compared with 2017, averaging 186 MBOED and 133 MBOED, respectively.
- Bakken—We operated an average of three rigs during the year in the Bakken. We continued our pad drilling with 51 operated wells drilled during the year and 85 operated wells brought online. Production increased 29 percent in 2018 compared with 2017, averaging 84 MBOED and 65 MBOED, respectively.
- Permian Basin—The Permian Basin is an area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. We hold approximately 800,000 net acres in the Permian, which includes 145,000 net unconventional acres. The Permian Basin produced 66 MBOED in 2018, increasing 6 percent compared to 2017, including 28 MBOED of unconventional production from the Delaware. We disposed of several noncore conventional assets throughout the year.

Dispositions
We completed the sale of our interests in the Barnett in the fourth quarter of 2018. Combined with the sale of several noncore conventional assets in the Permian Basin, production from the assets sold was 10 MBOED, approximately 3 percent of total Lower 48 production in 2018. For additional information on our asset dispositions, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Gulf of Mexico
At year-end 2018, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, totaling approximately 68,000 net acres, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 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.

Exploration

- *Conventional Exploration*
  In December 2017, we elected to withdraw from our Shenandoah leases. The withdrawal was effective February 17, 2018, substantially completing our exit from deepwater Gulf of Mexico.

- *Unconventional Exploration*
  Our onshore focus areas include the Niobrara in the Denver-Julesburg Basin, the Delaware in the Permian Basin, as well as several emerging plays such as the Louisiana Austin Chalk. We began acquiring early life-cycle acreage in the Austin Chalk in the fourth quarter of 2017, and currently hold approximately 225,000 net acres. We spud our first Austin Chalk well in late 2018 and plan to drill additional wells in 2019.

Facilities
Golden Pass LNG Terminal
We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $235 million at December 31, 2018. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. In January 2019, we entered into agreements to sell our 12.4 percent ownership interest in Golden Pass LNG Terminal and the affiliated Golden Pass Pipeline. We have also entered into agreements to amend our contractual obligations for remaining use of the facilities. Completion of the sale is subject to regulatory approval.

Other

- Lost Cabin Gas Plant—We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 246 million cubic-feet-per-day 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 continue throughout 2019. The expected production loss in 2019 is approximately 7 MBOED.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 110,000 barrel-per-day 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 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

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CANADA

Our Canadian operations mainly consist of an oil sands development in the Athabasca Region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2018, operations in Canada contributed 8 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

			2018			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Surmont	50.0 %	ConocoPhillips	-	-	66	66
Montney	100.0	ConocoPhillips	2	12	-	4
Total Canada			2	12	66	70

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. Production from the assets sold was 103 MBOED, approximately 62 percent of the total Canada segment production in 2017. For additional information on our asset dispositions, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Oil Sands
Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (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 greenhouse gas intensity and optimizing asset performance.

Exploration
We hold exploration acreage in three areas of Canada: onshore western Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada.

We hold approximately 145,000 net acres in the emerging unconventional Montney play in northeast British Columbia and 207,000 net acres in Canol Northwest Territories. Our Montney activity in 2018 included drilling 13 horizontal wells, completing two horizontal wells and acquiring approximately 37,000 additional net acres. Appraisal drilling and completions activity will continue in 2019 to further explore the area’s resource potential.

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EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2018, operations in Europe and North Africa contributed 19 percent of our worldwide liquids production and 18 percent of natural gas production.

Norway

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1 %	ConocoPhillips	53	45	60
Heidrun	24.0	Equinor	12	25	16
Alvheim	20.0	Aker BP	11	11	13
Visund	9.1	Equinor	5	44	12
Troll	1.6	Equinor	2	60	12
Other	Various	Equinor	8	9	10
Total Norway			91	194	123

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 which achieved first production in 2013 and 2015, respectively. Continued development drilling in the Greater Ekofisk Area will 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 floating production, storage and offloading (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.

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, as well as the Aasta Hansteen development in the Norwegian Sea, which achieved first production in December 2018.

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Exploration
In 2018, we participated in the Gekko appraisal well and sidetrack in the Alvheim Area of the North Sea and encountered hydrocarbons. The Gekko Discovery is currently under evaluation as a future tie-in to the Alvheim Facility. In 2018, we were awarded six new exploration licenses; PL911, PL912, PL917, PL919, PL935 and PL938; and one acreage addition, PL775B.

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 natural gas liquids processing facility in Teesside, England.

United Kingdom

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Britannia	58.7 %	ConocoPhillips	3	74	15
Britannia Satellites	26.3–93.8 *	ConocoPhillips	12	92	27
J-Area	32.5–36.5	ConocoPhillips	9	57	19
Clair	7.5 **	BP	6	1	6
East Irish Sea	100.0	Spirit Energy	-	30	5
Southern North Sea	Various	ConocoPhillips	-	22	4
Other	Various	Various	-	5	1
Total United Kingdom			30	281	77

**Includes the Chevron-operated Alder Field, ConocoPhillips equity interest is 26.3 percent.*
***See dispositions below for additional information.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia's line to St. Fergus, Scotland. The Britannia satellite fields, Callanish, Brodgar, Enochdhu and Alder, produce via subsea manifolds and pipelines linked to the Britannia Platform.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The J-Area gas is processed on the Judy Platform and transported through the Central Area Transmission System Pipeline, while liquids are transported to Teesside through the Norpipe system. Continued development drilling in the J-Area will provide additional volumes in the coming years as wells are brought online.

We have various ownership interests in several gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Production ceased in August 2018, and decommissioning activity in the Southern North Sea is ongoing. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 7.5 percent interest in the Clair Field, located in the Atlantic Margin. We completed the sale of a subsidiary holding a 16.5 percent interest in the Clair Field in December 2018 to BP. See the "Disposition" section below for more information. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities tie into existing oil and gas export pipelines to the Shetland Islands. First production for Clair Ridge was achieved in November 2018.

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Exploration
In 2018, we drilled the Jasmine 2A exploration well. The well encountered insufficient hydrocarbons and was expensed as a dry hole. In 2018, we were awarded two new exploration licenses in the J-Area, P2399 and P2456.

Transportation
We operate the Teesside oil and Theddlethorpe gas terminals in which we have 40.25 percent and 50 percent ownership interests, respectively. Decommissioning activity is ongoing at the Theddlethorpe gas terminal following cessation of production in the Southern North Sea. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

Disposition
In the fourth quarter of 2018, we completed a transaction to sell a ConocoPhillips subsidiary, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom to BP, and acquire their nonoperated interest in the Kuparuk Assets in Alaska. In 2018, our Europe and North Africa segment net production associated with the disposed 16.5 percent interest in the Clair Field was approximately 5 MBOED. See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Libya

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3 %	Waha Oil Co.	36	28	41
Total Libya			36	28	41

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 2018, we had 21 crude liftings from Es Sider. We expect a gradual, continued rampup in activity.

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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 2018, operations in the Asia Pacific and Middle East segment contributed 14 percent of our worldwide liquids production and 60 percent of natural gas production.

Australia and Timor Sea

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Australia Pacific LNG	37.5 %	ConocoPhillips/ Origin Energy	-	660	110
Bayu-Undan	56.9	ConocoPhillips	7	240	47
Athena/Perseus	50.0	ExxonMobil	-	35	6
Total Australia and Timor Sea			7	935	163

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 coalbed methane (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.

Two fully subscribed 4.5-million-metric-tonnes-per-year LNG trains have been completed. Approximately 3,900 net wells are ultimately expected to supply both the domestic gas market and the LNG sales contracts. 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 first APLNG Train 1 cargo sailed in January 2016, and APLNG Train 2 achieved first production in the third quarter of 2016. 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.

APLNG has an $8.5 billion project finance facility, which was fully drawn down and had an outstanding balance of $7.2 billion at December 31, 2018. In September 2018, APLNG successfully refinanced $1.4 billion of the project finance facility for a lower cost United States Private Placement (USPP) bond facility. Project finance interest payments are bi-annual, concluding September 2030.

For additional information, see Note 3—Variable Interest Entities (VIEs), 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 2018, we sold 157 billion gross cubic feet of LNG primarily to utility customers in Japan.

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A continuation of the Bayu-Undan Phase Three Development consisting of one subsea and two platform wells was completed with all three wells producing by November 2018.

Athena/Perseus

The Athena production license (WA-17-L) in which ConocoPhillips has a 50 percent working interest is located offshore Western Australia and contains part of the Perseus Field which straddles the boundary with WA-1-L, an adjoining license area. The production entitlement to natural gas produced from WA-17-L is forecast to end in the fourth quarter of 2019.

Greater Sunrise

In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals.

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. The TP 28 Western Australia State exploration permit was granted for five years from January 2017, with a 40 percent working interest and was excised from the existing permits as agreed between state and federal regulators. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. 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 leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. A 3-D seismic survey was completed over the Barossa and Caldita fields in 2016. The drilling of the Barossa-5A and Barossa-6 appraisal wells was completed in 2017 with good quality, gas-bearing reservoir intersected at both. Additionally, the retention lease over the Barossa Field was renewed during 2017. In April 2018, Barossa entered the front-end engineering and design (FEED) phase of development which will continue 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.

Indonesia

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Sumatra	45.0–54.0 %	ConocoPhillips	2	309	53
Total Indonesia			2	309	53

We operate three production sharing contracts (PSC) in Indonesia: The Corridor Block and South Jambi “B,” both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently, there is production from the Corridor Block.

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South Sumatra
The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. 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. Production from the South Jambi “B” PSC has reached depletion and field development has been suspended. This PSC will expire in January 2020.

Exploration
We have a 60 percent working interest in the Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 1.4 million gross acres. Technical evaluation is on-going to determine the block’s potential.

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

				2018		
	Interest		Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Penglai	49.0	%	CNOOC	30	-	30
Panyu	24.5		CNOOC	6	-	6
Total China				36	-	36

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2, which included six additional wellhead platforms and an FPSO vessel, was fully operational by 2009.

As part of further development of the Penglai 19-9 Field, the new wellhead platform J Project, which anticipates 62 wells, is progressing according to schedule, with 36 wells completed and brought online through December 2018.

The Penglai 19-3/19-9 Phase 3 Project was sanctioned in December 2015. This project consists of three new wellhead platforms and a central processing platform. First oil from Phase 3 was achieved in 2018.

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.

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The production period for Panyu 4-2, 5-1 and 11-6 will expire in 2019.

Exploration
In 2018, we participated in one successful appraisal well in the Bohai Penglai Field. We continued the Penglai full-field 3-D seismic program, covering existing and future development opportunities. The program is expected to complete in 2019.

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Malaysia

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Siakap North-Petai	21.0 %	Murphy	2	1	2
Gumusut	29.0	Shell	25	-	25
KBB	30.0	KPOC	1	41	8
Malikai	35.0	Shell	19	-	19
Total Malaysia			47	42	54

We own interests in six PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, Block SK304, Block SK313 and Block WL4-00 are located off the eastern Malaysian state of Sarawak.

Block G
We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014.

We own a 35 percent interest in Malikai. The field achieved first production in December 2016, ramping to peak production in 2018. The KMU-1 exploration well was completed and started producing in 2018.

Block J
First production from the Gumusut Field occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014. Our ownership in the Gumusut Field is currently at 29 percent following the finalization of the Malaysia-Brunei unitization and a redetermination of the Block J and Block K Malaysia Unit, both in 2017. The drilling of the Gemilang-1 exploration well in Block J is complete and the results are under review. Gumusut Phase 2 infill drilling and first oil from Phase 2 are expected in 2019.

KBBC
We have a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Production in 2018 was impacted by unplanned downtime related to the rupture of a third-party pipeline which carries gas production from the Kebabangan gas field to market. Development options for the Kamunsu East gas field are being evaluated.

Exploration
In the fourth quarter of 2016, we entered into a farm-in agreement to acquire a 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block, effective January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS.

We were awarded Block WL4-00, which encompasses 0.6 million gross acres, in January 2017. We have a 50 percent operated interest in this block which includes the Salam-1 oil discovery.

We completed a 3-D seismic survey in Block SK 313 and Block WL4-00 in 2017. Two wells were drilled in Block WL4-00 in 2018 and discovered hydrocarbons. Further exploration drilling is expected to occur in 2019.

We were awarded Block SK304 in May 2018, which encompasses 2.1 million gross acres. We completed a 3-D seismic survey in this block in 2018.

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Brunei
Exploration
In October 2018, we assigned our 6.25 percent working interest in the deepwater Block CA-2 PSC to Brunei National Petroleum Company Sendirian Berhad.

Qatar

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
QG3	30.0 %	Qatargas Operating Company Limited	21	371	83
Total Qatar			21	371	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 and Chile.

Colombia
Exploration
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 is expected to continue into 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. Community engagement and environmental permitting activities are expected to continue in 2019.

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

Argentina
Exploration
We received government approval in January 2019 for a 50 percent nonoperated interest in the El Turbio Este Block in the Austral Basin.

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.

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OTHER

Marketing Activities

Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, 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 United States, 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 natural gas liquids revenues are derived from production in the United States, 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 (VIEs), 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 United Kingdom, 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 United States by MWCC and provides well capping and containment capability outside the United States.

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 United Kingdom, 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 fewer emissions, improve the efficiency of our company's 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, 2018. No difference exists between our estimated total proved reserves for year-end 2017 and year-end 2016, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2018.

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 1.5 trillion cubic feet of natural gas, including approximately 243 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 73 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2029. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves 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 proved undeveloped reserves.

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, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 3, 2018, 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 2017. 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 2018, we held a total of 814 active patents in 50 countries worldwide, including 333 active U.S. patents. During 2018, we received 29 patents in the United States and 67 foreign patents. Our products and processes generated licensing revenues of $53 million related to activity in 2018. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Health, Safety and Environment

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental 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 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 also have detailed processes in place to address 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 65 through 69 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2018 and those expected for 2019 and 2020.

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 U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC's website at *www.sec.gov*.

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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, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have experienced significant declines from their historic levels during 2013 and 2014, with excess of supply relative to global demand leading to global inventory builds. Although commodity prices began to rise in 2018, there was a sharp drop in crude oil prices in the fourth quarter of 2018, ending 2018 lower than where they started at the beginning of the year for the first time since 2015. Given volatility in commodity price drivers and the worldwide economic environment generally, 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, natural gas liquids and LNG. The factors influencing these prices are beyond our control.

Lower crude oil, bitumen, natural gas, natural gas liquids and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity, and on the amount of dividends we elect to declare and pay on our common stock. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our proved reserves and 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, natural gas liquids 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 distributions to our stockholders; however, our Board of Directors may determine that our funds generated by operations, after deducting operating expenses, are not sufficient to pay our desired levels of distributions to our stockholders or to pay distributions to our stockholders at all.

Additionally, our Board of Directors has authorized a $15 billion share repurchase program, of which $9 billion of repurchase authority remained as of December 31, 2018. 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 distributions, among others.

Any downward revision in the amount of distributions 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. For example, due to the significant decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG in 2015, and the expectation that these prices could remain depressed, the major ratings agencies conducted a review of the oil and gas industry and downgraded our debt ratings and those of several companies operating in the industry in 2016. 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 $0.4 billion of the $2 billion settlement in 2018. If PDVSA were to default on any of its remaining payment obligations under this agreement, we may be 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 natural gas liquids production will decline, resulting in an adverse impact to our business.

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we 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 natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, 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 natural gas liquids 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 natural gas liquids 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 natural gas liquids reserves could impair the quantity and value of those reserves.

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. 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. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

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 United States 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 greenhouse gas 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 tight oil 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 greenhouse gas 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 greenhouse gas 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 United States 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 greenhouse gas emission reduction goals every five years beginning in 2020. While the United States announced its intention to withdraw from the Paris Agreement, there is no guarantee that the commitments made by the United States will not be implemented, in whole or in part, by U.S. state and local governments or by major corporations headquartered in the United States. 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 greenhouse gas 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 greenhouse gases 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.

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, a state government, and a trade association in California, New York, Washington, Rhode Island and Maryland have filed lawsuits against several 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 our business operations are designed and operated 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 United States 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. Environmental Protection Agency (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 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 55 percent of our hydrocarbon production was derived from production outside the United States in 2018, and 41 percent of our proved reserves, as of December 31, 2018, were located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids 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 particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty 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 natural gas liquids, or the unavailability of adequate gathering, processing, compression, transportation, and pipeline facilities and equipment for our production of crude oil, bitumen, natural gas and natural gas liquids.

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 natural gas liquids 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, natural gas liquids 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, natural gas liquids 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, natural gas liquids and LNG for sale or we may be forced to curtail our production of crude oil, bitumen, natural gas, natural gas liquids or LNG.

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.

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, 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. Activities in deepwater areas 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, actual or attempted 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.

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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 2018, as well as matters previously reported in our 2017 Form 10-K and our first-, second- and third-quarter 2018 Form 10-Qs that were not resolved prior to the fourth quarter of 2018. 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, through the payment of a penalty of $457,750 and the implementation of measures designed to prevent a reoccurrence. The company will work with the Commission to promptly resolve this matter.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Catherine A. Brooks	Vice President and Controller	53
William L. Bullock, Jr.	President, Asia Pacific & Middle East	54
Ellen R. DeSanctis	Senior Vice President, Corporate Relations	62
Matt J. Fox	Executive Vice President and Chief Operating Officer	58
Michael D. Hatfield	President, Alaska, Canada and Europe	52
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	56
Andrew D. Lundquist	Senior Vice President, Government Affairs	58
Dominic E. Macklon	President, Lower 48	49
Kelly B. Rose	Senior Vice President, Legal, General Counsel and Corporate Secretary	52
Don E. Wallette, Jr.	Executive Vice President and Chief Financial Officer	60

**On February 15, 2019.*

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 14, 2019. 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.

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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.

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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	
	2018	2017
First	**$ 0.285**	0.265
Second	**0.285**	0.265
Third	**0.285**	0.265
Fourth	**0.305**	0.265
Number of Stockholders of Record at January 31, 2019*		44,084

**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 January 31, 2017, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.265 per share, compared with the previous quarterly dividend of $0.25 per share.

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.

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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, 2018	4,155,118	$ 74.45	4,155,118	$ 9,492
November 1-30, 2018	4,642,077	66.57	4,642,077	9,183
December 1-31, 2018	4,808,691	63.87	4,808,691	8,875
Total fourth-quarter 2018	13,605,886	$ 68.02	13,605,886	$ 8,875

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

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2 billion. On July 12, 2018, we announced plans to further accelerate our 2018 share repurchases to $3 billion. The 2018 expansion to $3 billion, combined with the $3 billion of shares repurchased during 2016 and 2017, fully utilized the Board of Directors' existing share repurchase authorization of $6 billion. As a result, our Board authorized an additional $9 billion for share repurchases, at any time or from time to time (whether before, on or after December 31, 2019), bringing the total program authorization to $15 billion. Acquisitions for the share repurchase program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. 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, 2013, to December 31, 2018. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index and our performance peer group consisting of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Anadarko, Apache, Marathon Oil Corporation, Devon and Occidental, weighted according to the respective peer's stock market capitalization at the beginning of each annual period. The comparison assumes $100 was invested on December 31, 2013, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer group and assumes that all dividends were reinvested.

LOGO

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2018	2017	2016	2015	2014
Sales and other operating revenues	**$ 36,417**	29,106	23,693	29,564	52,524
Income (loss) from continuing operations	**6,305**	(793)	(3,559)	(4,371)	5,807
Per common share					
Basic	**5.36**	(0.70)	(2.91)	(3.58)	4.63
Diluted	**5.32**	(0.70)	(2.91)	(3.58)	4.60
Income from discontinued operations	**-**	-	-	-	1,131
Net income (loss)	**6,305**	(793)	(3,559)	(4,371)	6,938
Net income (loss) attributable to ConocoPhillips	**6,257**	(855)	(3,615)	(4,428)	6,869
Per common share					
Basic	**5.36**	(0.70)	(2.91)	(3.58)	5.54
Diluted	**5.32**	(0.70)	(2.91)	(3.58)	5.51
Total assets	**69,980**	73,362	89,772	97,484	116,539
Long-term debt	**14,856**	17,128	26,186	23,453	22,383
Cash dividends declared per common share	**1.16**	1.06	1.00	2.94	2.84

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 interest in the San Juan Basin.

Net income (loss) and net income (loss) attributable to ConocoPhillips in 2014 includes income from discontinued operations as a result of the sale of our interest in our Nigeria business.

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 76.

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 the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 16 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; lower-risk conventional assets in North America, Europe, Asia and Australia; liquefied natural gas (LNG) developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2018, we employed approximately 10,800 people worldwide and had total assets of $70 billion.

Overview

In 2018, the energy industry continued to be volatile. Forecasts of worldwide economic growth and strong global demand for crude oil at the beginning of the year transitioned to concerns about a worldwide economic slowdown and an oversupply of crude oil by the end of the year. Additionally, production from major oil producing countries, including the United States, was strong. These factors caused crude oil prices to fall rapidly in the fourth quarter of 2018. Our business strategy anticipates prices will remain cyclical and is designed to be resilient in lower price environments, with significant upside during periods of higher prices.

Our value proposition principles, namely to focus on returns, maintain financial strength, grow our dividend and pursue disciplined growth, are being executed in accordance with our priorities for allocating cash flows from the business. These priorities are: invest capital at a level that maintains flat production volumes and pays 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; repurchase shares to provide value to our shareholders; and invest capital to grow our cash from operations.

In 2018, we successfully delivered on our priorities. We increased our quarterly dividend by 15 percent to $0.305 per share; reduced our debt by $4.7 billion, achieving our debt reduction target 18 months ahead of plan and received credit rating upgrades from Fitch, Moody's and Standard & Poor's; repurchased 45 million shares of our common stock totaling $3.0 billion and received Board authorization for an incremental $9 billion of share repurchases; and added to our low cost of supply resource base, including increasing our legacy asset position in Alaska through two separate acquisitions.

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Portfolio optimization, debt reduction and disciplined capital investment have positioned our company to navigate through periods of volatile energy prices. In December 2018, we announced our 2019 capital budget of $6.1 billion, which is less than our 2018 capital expenditures and investments of $6.8 billion. Our 2019 capital budget is relatively flat to the prior year when excluding $0.6 billion of acquisitions made in 2018. At this level of capital, production excluding Libya is expected to be 1,300 to 1,350 thousand barrels of oil equivalent per day (MBOED) in 2019 and would exceed 2018 production excluding Libya of 1,242 MBOED. This plan anticipates cash provided by operating activities in excess of capital expenditures and investments at prices above $40 per barrel West Texas Intermediate (WTI).

Key Operating and Financial Summary

Significant items during 2018 included the following:

- Cash provided by operating activities was $12.9 billion and exceeded capital expenditures and investments of $6.8 billion, share repurchases of $3 billion and dividends of $1.4 billion.
- The $4.4 billion of share repurchases and dividends represents 34 percent of cash provided by operating activities.
- Reduced debt by $4.7 billion and achieved $15 billion debt target 18 months ahead of plan.
- Received credit rating upgrades from Fitch, Moody's and Standard & Poor's.
- Full-year production excluding Libya of 1,242 MBOED; underlying production grew 18 percent on a production per debt-adjusted share basis.
- Increased full-year Lower 48 Big 3 production—Eagle Ford, Bakken and Delaware—by 37 percent.
- Achieved first production from Bayu-Undan final development phase, GMT-1, Bohai Phase 3, Aasta Hansteen and Clair Ridge.
- Acquired additional working interest in our legacy assets in Alaska and increased our acreage in the liquids-rich Montney play in Canada and in the early-life cycle unconventional Louisiana Austin Chalk.
- Executed successful exploration program in Alaska and started drilling in Louisiana Austin Chalk.
- Reached a settlement agreement with Petroleos de Venezuela, S.A. (PDVSA) to fully recover the International Chamber of Commerce (ICC) arbitration award of approximately $2 billion; recognized $430 million before-tax toward the settlement.
- Generated disposition proceeds of $1.1 billion from noncore asset sales.
- Year-end proved reserves of 5.3 billion barrels of oil equivalent (BOE); 147 percent total reserve replacement and 109 percent organic replacement ratio.

Operationally, we continue to focus on safely executing our capital program and remaining diligent on our costs. Production, including Libya, of 1,283 MBOED decreased 7 percent in 2018 compared with 2017. The volume from closed dispositions was approximately 200 MBOED in 2017 and 15 MBOED in 2018. The volume from acquisitions was less than 10 MBOED in 2018. Production from Libya was 21 MBOED in 2017 and 41 MBOED in 2018. Our underlying production, which excludes the full-year impact of acquisitions, dispositions, and Libya, increased over 5 percent in 2018 compared with 2017. Underlying production on a per debt-adjusted share basis grew by 18 percent compared to 2017. Production per debt-adjusted share is calculated on an underlying production basis using ending period debt divided by ending share price plus ending shares outstanding. We believe production per debt-adjusted share is useful to investors as it provides a consistent view of production on a total equity basis by converting debt to equity and allows for comparison across peer companies.

In the second quarter of 2018, we obtained regulatory approvals and completed a transaction with Anadarko Petroleum Corporation to acquire its 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. In 2018, our Alaska segment net production included 7 MBOED associated with the additional interest acquired. In addition, we now have 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery.

In the fourth quarter of 2018, we completed a transaction with BP to acquire its nonoperated interest in the Greater Kuparuk Area and Kuparuk Transportation Company (Kuparuk Assets) in Alaska, and to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. In 2018, our Alaska segment net production included 1 MBOED associated with the additional interest acquired in the Greater Kuparuk Area, and net production in our Europe and North Africa segment included 5 MBOED related to the disposed 16.5 percent interest in the Clair Field. We recognized a $774 million after-tax gain in the fourth quarter related to this transaction. Excluding receipt of $253 million in customary adjustments, this transaction was cash neutral.

In the fourth quarter of 2018, we completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments. In 2018, our Lower 48 segment net production included 8 MBOED related to the disposed interest in the Barnett, of which approximately 55 percent was natural gas and 45 percent was natural gas liquids. After-tax impairment charges of $69 million were recognized during 2018.

In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals. No production or reserve impacts are associated with the sale. Proceeds from this transaction will be used for general corporate purposes. The Greater Sunrise Fields are included in our Asia Pacific and Middle East segment.

For more information regarding the accounting impacts of these transactions, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Also during 2018, we entered into a settlement agreement with PDVSA to recover approximately $2 billion, which reflects the full amount awarded to ConocoPhillips by an arbitral tribunal constituted under the rules of the ICC. PDVSA has agreed to recognize the ICC judgment and to make payments over the next four and a half years. During the year, we recognized in other income $417 million after-tax, consisting of $200 million in cash and the remainder in commodity inventory, the majority of which was sold by year end. For more information, see Note 4—Inventories and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Business Environment

Brent crude oil prices averaged over $60 per barrel in the first quarter of 2018, rising to over $70 per barrel in the second and third quarters of 2018, before falling to the $50 per barrel range at the end of the year. The energy industry has periodically experienced this type of volatility due to fluctuating supply-and-demand conditions. 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 disciplined financial and operational priorities that underpin our value proposition.

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 greenhouse gas emission intensity by 2030. Our sustainability efforts continued through 2018 with a focus on advancing our action plans for climate change, biodiversity, water and human rights. 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. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved Health, Safety and Environment and operational performance.

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

  - 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 2018, our production and operating expenses were relatively flat to 2017.

  - Maintain capital 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 diverse, low cost of supply, programs in our resource base. Our cash allocation priorities call for the investment of sufficient capital to maintain production and pay the existing dividend. Additional allocations of capital toward growth projects will be dependent on satisfaction of other financial priorities. In setting our capital plans, we exercise a disciplined approach that evaluates projects on a cost of supply basis and is focused on value maximization and cash flow expansion.

    In December 2018, we announced a 2019 capital budget of $6.1 billion, including $3.8 billion of sustaining capital to maintain existing production levels, and $2.3 billion to grow production via short-cycle unconventional programs, future major projects and exploration activities.

  - Optimize our portfolio. We continue to optimize our asset portfolio by focusing on low cost of supply assets that support our strategy. In 2018, we continued to dispose of or market certain noncore assets and made two acquisitions in Alaska to enhance our existing legacy asset position. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

- Maintain financial strength. We believe financial strength is critical in a cyclical business such as ours. In 2018, we reduced our debt by $4.7 billion to $15.0 billion at year end, achieving our debt reduction target 18 months ahead of plan and received credit rating upgrades from Fitch, Moody’s and Standard & Poor’s. We expect to retire outstanding debt as it matures and exercise flexibility in paying down our other debt instruments.

- Return capital to shareholders. In 2018, we paid dividends on our common stock of approximately $1.4 billion and repurchased $3 billion of our common stock, representing 34 percent of our cash provided by operating activities. We believe in delivering value to our shareholders through the price cycles. As a result, we set a priority to increase our dividend rate annually and consistently repurchase shares on a dollar cost average basis. Since we initiated our current share repurchase program in late

2016, we have bought back $6 billion of shares, with $9 billion remaining on our existing authorization. Our 2018 dividends, share repurchases, and capital program were fully funded with cash provided by operating activities.

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. In October 2018, we announced a dividend increase for the second time this year, an additional 7 percent, resulting in a quarterly dividend rate of $0.305 per share.

In addition to the $6 billion of shares repurchased in 2016 through the end of 2018, in July 2018 we announced the authorization of an additional $9 billion share repurchases. We expect to execute $3 billion of this $9 billion share repurchase program in 2019. 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."

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

  - Successful exploration, exploitation and development of new and existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.

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 2018, our reserve replacement, which included a net increase of 0.2 billion BOE from sales and purchases, was 147 percent. Increased crude oil reserves accounted for over 90 percent of the total change in reserves. Our organic reserve replacement, which excludes the impact of sales and purchases, was 109 percent in 2018. Approximately 33 percent of organic reserve additions are from Lower 48 unconventional assets, 29 percent from Alaska and 22 percent from Asia Pacific and Middle East.

In the five years ended December 31, 2018, our reserve replacement was negative 30 percent, reflecting the impact of asset dispositions and lower prices during that period. Our organic reserve replacement during the five years ended December 31, 2018, which excludes a decrease of 2.1 billion MMBOE related to sales and purchases, was 44 percent, reflecting development activities as well as lower prices during that period.

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 we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations. Such innovations enhance our ability to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

- Develop and retain a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills 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 Organization of Petroleum Exporting Countries (OPEC), environmental laws, tax regulations, governmental policies and weather-related disruptions. The following graph depicts the average benchmark prices for WTI crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:

LOGO

Brent crude oil prices averaged $71.04 per barrel in 2018, an increase of 31 percent compared with $54.27 per barrel in 2017. Similarly, WTI crude oil prices increased 28 percent from $50.90 per barrel in 2017 to $64.92 per barrel in the same period of 2018. Crude oil prices improved year over year due to slower growth in global oil production and robust growth in global oil demand. Oil price volatility escalated in the fourth quarter of 2018 due to geopolitics and concerns about future economic growth.

Henry Hub natural gas price averages were relatively unchanged, at $3.09 per million British thermal units (MMBTU) in 2018 compared with $3.11 per MMBTU in 2017. Despite record high natural gas production, prices remained relatively flat year over year as relatively low inventories and strong demand offset production growth.

Our realized natural gas liquids prices averaged $30.48 per barrel in 2018, an increase of 21 percent compared with $25.22 per barrel in 2017, in line with marker movements.

The Western Canada Select (WCS) differential to WTI at Hardisty weakened by $14 per barrel in 2018 relative to 2017 due to a lack of pipeline egress coupled with increasing supply from western Canada. The weaker WCS differential offset year-over-year gains in WTI, resulting in the WCS price at Hardisty remaining flat in 2018 compared with 2017 at $39 per barrel. 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 realized bitumen price was $22.29 per barrel in 2018, a decrease of 2 percent compared with $22.66 per barrel in 2017.

Our worldwide annual average realized price was $53.88 per barrel of oil equivalent (BOE) in 2018, an increase of 37 percent compared with $39.19 per BOE in 2017. The improvement reflects stronger marker prices, as well as a shift in our portfolio toward a higher mix of crude oil and less of bitumen and natural gas.

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 United States. 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; delay of plans to develop areas such as unconventional fields; and underutilization of LNG regasification facilities. 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 properties, plants and equipment 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. For additional information on our impairments in 2018, 2017 and 2016, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

- Effective tax rate. Our operations are located 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 United States. 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 assets in Venezuela were expropriated in 2007. Our production operations in Libya and related oil exports were suspended or significantly curtailed periodically over the last several years due to the closure of the Es Sider crude oil export terminal. In 2016, the U.K. government enacted tax legislation which reduced our U.K. corporate tax rate by 10 percent.

We applied the guidance in Staff Accounting Bulletin (SAB) 118 when accounting for the enactment-date effects of the Tax Cuts and Jobs Act (Tax Legislation) in 2017 and throughout 2018. At December 31, 2017, our assessment was ongoing for the enactment-date income tax effects of the Tax Legislation under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 740, “Income Taxes,” for the following aspects: remeasurement of deferred tax assets and liabilities, one-time transition tax, and tax on global intangible low-taxed income. As of

December 31, 2018, we have now completed our assessment of the enactment-date income tax effects of the Tax Legislation. During 2018, we recognized adjustments of $10 million to the provisional tax benefit amount of $852 million recorded at December 31, 2017, and included these adjustments as a component of income tax expense. While we still anticipate the Tax Legislation will provide a positive impact to our U.S. operations in the future primarily because of the reduced U.S. federal statutory rate, we do not expect to realize cash tax benefits from the Tax Legislation until we move into a U.S. tax paying position. For additional information, see Note 19—Income Taxes, in the Notes to Consolidated Financial Statements.

Our management carefully considers the fiscal and regulatory environment when evaluating projects or determining the levels and locations of our activity.

Outlook

First-quarter 2019 production is expected to be 1,290 to 1,330 MBOED, reflecting the impacts of a planned turnaround in Qatar of approximately 15 MBOED and government-mandated production curtailment in Canada of approximately 10 MBOED. Production is expected to ramp up in the second half of the year, with full-year 2019 production expected to be 1,300 to 1,350 MBOED. Production guidance for 2019 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 received.

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.

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RESULTS OF OPERATIONS

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		**2018**	2017	2016
Alaska	$	**1,814**	1,466	319
Lower 48		**1,747**	(2,371)	(2,257)
Canada		**63**	2,564	(935)
Europe and North Africa		**1,866**	553	394
Asia Pacific and Middle East		**2,070**	(1,098)	209
Other International		**364**	167	(16)
Corporate and Other		**(1,667)**	(2,136)	(1,329)
Net income (loss) attributable to ConocoPhillips	$	**6,257**	(855)	(3,615)

2018 vs. 2017

Net income attributable to ConocoPhillips increased $7,112 million in 2018. The increase was mainly due to:

- Higher realized commodity prices on a more liquids-weighted portfolio.
- The absence of a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the marketing of our Barnett asset, recognized in the second quarter of 2017.
- The absence of a $2.4 billion before- and after-tax impairment of our equity investment in Australia Pacific LNG Pty Ltd (APLNG), recognized in the second quarter of 2017.
- Recognition of $774 million after-tax gain on the Clair disposition in the United Kingdom, in the fourth quarter of 2018.
- Lower depreciation, depletion and amortization (DD&A) expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Recognition of $417 million after-tax in other income from a settlement agreement with PDVSA in 2018.
- Lower exploration expenses, primarily due to the absence of first quarter 2017 charges in our Lower 48 and Other International segments.
- Lower interest and debt expense because of a lower debt balance.
- Higher equity earnings in Qatar Liquefied Gas Company Limited (3) (QG3) and APLNG, primarily due to higher realized LNG prices, partly offset by the absence of volumes in 2018 related to the disposition of our interest in the FCCL Partnership in Canada in 2017.

These increases in net income were partly offset by:

- The absence of $1.6 billion in after-tax gains related to the sale of certain Canadian assets in 2017.
- The absence of a $996 million deferred tax benefit related to the disposition of certain Canadian assets, recognized in the first quarter of 2017.
- The absence of deferred tax benefits totaling $852 million related to the Tax Legislation enacted on December 22, 2017.
- An unrealized loss of $437 million on our Cenovus Energy common shares in 2018.
- The absence of a $337 million after-tax award, including interest, from an arbitration settlement with The Republic of Ecuador in 2017.

2017 vs. 2016

Loss attributable to ConocoPhillips decreased $2,760 million in 2017. The decrease was mainly due to:

- Higher commodity prices.
- Lower DD&A expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Higher gains on dispositions, primarily due to a $1.6 billion after-tax gain in 2017 on the sale of certain Canadian assets.
- Recognition of deferred tax benefits totaling $996 million, primarily related to the disposition of certain Canadian assets.
- Recognition of deferred tax benefits totaling $852 million related to the Tax Legislation enacted on December 22, 2017.
- Improved equity earnings, mainly due to higher realized prices, lower DD&A from asset disposition impacts, and the absence of a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to the U.S. dollar. These increases were partly offset by lower volumes from the disposition of our interest in the FCCL Partnership.
- Lower exploration expenses mainly due to reduced leasehold impairment expense, dry hole costs and other exploration expenses.
- A $337 million after-tax award, including interest, from an arbitration settlement with The Republic of Ecuador.
- Lower production and operating expenses, primarily due to asset disposition impacts.
- Lower net interest expense, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and reduced debt.

The reduction in loss was partly offset by:

- Higher proved property and equity investment impairments, including a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the marketing of the Barnett, as well as a $2.4 billion before- and after-tax impairment of our equity investment in APLNG.
- Lower volumes primarily due to asset dispositions in our Lower 48, Asia Pacific and Middle East, and Canada segments, as well as normal field decline.
- A $238 million after-tax charge associated with our early retirements of debt in 2017.

Income Statement Analysis

2018 vs. 2017

<u>Sales and other operating revenues</u> increased 25 percent in 2018, due to higher realized commodity prices, mainly crude oil, on a portfolio with a higher mix of crude oil and less of bitumen and natural gas. Partly offsetting this increase, were lower natural gas volumes sold due to 2017 dispositions in the Lower 48 and Canada.

<u>Equity in earnings of affiliates</u> increased $302 million in 2018. The increase in equity earnings was primarily due to higher earnings from QG3 and APLNG as a result of higher LNG prices for both affiliates and higher oil prices in QG3. Partly offsetting this increase, was the absence of equity in earnings resulting from the disposition of our investment in the FCCL Partnership in 2017.

<u>Gain on dispositions</u> decreased $1,114 million in 2018. The decrease was primarily due to the absence of a $2.1 billion before-tax gain on the sale of certain Canadian assets recognized in 2017, partly offset by a $715 million before-tax gain recognized in the fourth quarter of 2018 on 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 United Kingdom. For additional information concerning gain on dispositions, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Other income decreased $356 million in 2018, mainly due to a $437 million unrealized loss on our Cenovus Energy common shares in 2018 and the absence of a $337 million arbitration settlement, including interest, with The Republic of Ecuador in 2017. Partly offsetting the decrease, was $430 million before-tax from a settlement agreement with PDVSA in 2018.

For discussion of our Cenovus Energy shares, see Note 7—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements. For discussion of our Ecuador and PDVSA settlements, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Purchased commodities increased 15 percent in 2018, mainly due to higher crude oil volumes purchased and higher crude oil prices.

Production and operating expenses increased 1 percent in 2018, primarily due to costs associated with higher underlying production volumes as well as higher maintenance and wellwork, largely offset by the absence of costs resulting from 2017 dispositions in our Canada and Lower 48 segments.

Exploration expenses decreased $565 million in 2018, primarily as a result of lower dry hole costs, leasehold impairment expense and other exploration expenses.

Dry hole costs were reduced primarily due to the absence of before-tax charges of $288 million for multiple Shenandoah wells in the deepwater Gulf of Mexico, including wells previously suspended. These charges were reflected in our Lower 48 segment during 2017.

Leasehold impairment expense was reduced mainly due to the absence of before-tax charges of $51 million for Shenandoah and $38 million for certain Lower 48 mineral assets, both recognized in 2017.

Other exploration expenses were reduced mainly due to the absence of a $43 million before-tax charge for the cancellation of our Athena drilling rig contract and other rig stacking costs in our Other International segment in 2017.

For additional information on leasehold impairments and other exploration expenses, see Note 8—Suspended Wells and Other Exploration Expenses, and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

DD&A decreased $889 million in 2018, mainly due to lower unit-of-production rates from positive reserve revisions and impacts from the 2017 dispositions in our Canada and Lower 48 segments, partly offset by increased underlying production volumes.

Impairments decreased $6.6 billion in 2018, mainly due to the absence of 2017 impairments of $3.9 billion before-tax related to our former interests in the San Juan Basin and the Barnett, both in our Lower 48 segment, as well as a $2.4 billion before- and after-tax impairment of our equity investment in APLNG. For additional information, see Note 6—Investments, Loans and Long-Term Receivables and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes increased $239 million in 2018, primarily due to higher production taxes in Alaska and the Lower 48 corresponding with higher realized commodity prices.

Interest and debt expense decreased $363 million in 2018, primarily due to lower debt balances.

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

2017 vs. 2016

Sales and other operating revenues increased 23 percent in 2017, mainly due to higher realized prices across all commodities, partly offset by lower sales volumes, primarily in our Lower 48, Asia Pacific and Middle East, and Canada segments as a result of dispositions.

Equity in earnings of affiliates increased $720 million in 2017. The increase in equity earnings was primarily due to higher realized commodity prices at QG3, APLNG and FCCL; the absence of a 2016 deferred tax charge of $174 million resulting from a tax functional currency change; and reduced costs mainly from the disposition of our interest in the FCCL Partnership. The increase in earnings was partly offset by lower volumes as a result of our FCCL disposition.

Gain on dispositions increased $1.8 billion in 2017. The increase was primarily due to a before-tax gain of $2.1 billion on the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets. For additional information on gains on dispositions, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Other income increased $274 million in 2017, mainly due to a $337 million before- and after-tax arbitration award from The Republic of Ecuador. The increase was partly offset by the absence of a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust and a $76 million before-tax damage claim settlement, both in our Lower 48 segment in 2016.

Purchased commodities increased 25 percent in 2017, mainly due to higher commodity prices and increased activity.

Selling, general and administrative expenses decreased 10 percent in 2017, primarily due to reduced restructuring expenses, lower headcount and reduced activity.

Exploration expenses decreased 51 percent in 2017, primarily as a result of lower leasehold impairment expense, dry hole costs and other exploration expenses.

Leasehold impairment expense was reduced mainly due to the absence of 2016 before-tax charges of $203 million for our Gibson and Tiber leaseholds. The expense was further reduced by the absence of before-tax charges of $95 million for our Melmar leasehold and $79 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by a before-tax charge of $51 million for Shenandoah in deepwater Gulf of Mexico and a before-tax charge of $38 million for certain mineral assets in our Lower 48 segment, both in 2017.

Dry hole costs were reduced primarily due to the absence of 2016 before-tax charges in deepwater Gulf of Mexico of $249 million for our Gibson and Tiber wells, and $128 million for our Melmar well. The absence of a $256 million before-tax charge in 2016 for two dry holes in Nova Scotia further reduced costs. The reduction in dry hole costs was partly offset by 2017 before-tax charges of $288 million for multiple wells in Shenandoah, including wells previously suspended, and $63 million for several wells in the Powder River Basin.

Other exploration expenses were reduced mainly due to the absence of a $146 million before-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract, as well as lower rig stacking costs in Angola. The decrease in expense was partly offset by a $43 million net before-tax charge in 2017 for the settlement of our drilling rig contract in Angola.

For additional information on leasehold impairments and other exploration expenses, see Note 8—Suspended Wells and Other Exploration Expenses, and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

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DD&A decreased 24 percent in 2017, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts in our Canada and Lower 48 segments.

Impairments increased $6.5 billion in 2017. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Interest and debt expense decreased 12 percent in 2017, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and reduced debt balances.

Other expenses included before-tax charges of $302 million in 2017 for premiums on early debt retirements.

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

	2018	2017	2016
Average Net Production			
Crude oil (MBD)(1)	**653**	599	598
Natural gas liquids (MBD)	**102**	111	145
Bitumen (MBD)	**66**	122	183
Natural gas (MMCFD)(2)	**2,774**	3,270	3,857
Total Production (MBOED)(3)	**1,283**	1,377	1,569
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)	**$ 68.13**	51.96	40.86
Natural gas liquids (per barrel)	**30.48**	25.22	16.68
Bitumen (per barrel)	**22.29**	22.66	15.27
Natural gas (per thousand cubic feet)	**5.65**	4.07	3.00
	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical, lease rental, and other(4)	**$ 274**	368	728
Leasehold impairment	**56**	136	466
Dry holes	**39**	430	718
	$ 369	934	1,912

(1)Thousands of barrels per day.
(2)Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.
(3)Thousands of barrels of oil equivalent per day.
(4)Certain prior period amounts in 2017 and 2016 have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07.
See Note 2—Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2018, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

2018 vs. 2017

Total production, including Libya, of 1,283 MBOED decreased 7 percent in 2018 compared with 2017, primarily due to:

- Disposition impacts from asset sales in Canada and the Lower 48 in 2017.
- Normal field decline.
- Higher unplanned downtime, including a third-party pipeline outage in Malaysia in 2018.

The decrease in production during 2018 was partly offset by:

- New wells online, primarily from tight oil plays in the Lower 48 and Malikai in Malaysia.
- Improved drilling and well performance in Alaska, Norway, Lower 48 and China.
- The continued rampup in Libya.

Production excluding Libya was 1,242 MBOED in 2018 compared with 1,356 MBOED in 2017. The volume from closed dispositions was approximately 200 MBOED in 2017 and 15 MBOED in 2018. The volume from acquisitions was less than 10 MBOED in 2018. Our underlying production, which excludes the full-year impact of acquisitions, dispositions, and Libya, increased over 5 percent in 2018 compared with 2017.

2017 vs. 2016

Total production, including Libya, of 1,377 MBOED decreased 12 percent in 2017 compared with 2016, primarily due to:

- Reductions from noncore asset dispositions, including Canada and the Lower 48 in 2017 and the sale of our interest in the Block B production sharing contract in Indonesia in 2016.
- Normal field decline.

The decrease in production during 2017 was partly offset by:

- Production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont in Canada; and APLNG in Australia.
- Improved drilling and well performance in Alaska, Norway and China.

Excluding Libya, our 2017 production was 1,356 MBOED. Adjusted for the impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, our underlying production increased 32 MBOED, or 3 percent, compared with 2016.

Alaska

	2018	2017	2016
Net Income Attributable to ConocoPhillips (millions of dollars)	**$ 1,814**	1,466	319
Average Net Production			
Crude oil (MBD)	**171**	167	163
Natural gas liquids (MBD)	**14**	14	12
Natural gas (MMCFD)	**6**	7	25
Total Production (MBOED)	**186**	182	179
Average Sales Prices			
Crude oil (per barrel)	**$ 70.86**	53.33	41.93
Natural gas (per thousand cubic feet)	**2.48**	2.72	5.22

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids and natural gas. In 2018, Alaska contributed 23 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

2018 vs. 2017

Alaska reported earnings of $1,814 million in 2018, compared with earnings of $1,466 million in 2017. The increase in earnings was mainly due to higher realized crude oil prices. Additionally, earnings were improved due to the absence of a $110 million after-tax impairment related to our small interest in the Point Thomson Unit, recognized in the first quarter of 2017; a $98 million reduction in tax valuation allowance, recognized in the fourth quarter of 2018; lower DD&A expense from reserve additions; and a $79 million after-tax benefit resulting from an accrual reduction due to a transportation cost ruling by the Federal Energy Regulatory Commission (FERC), recorded in the first quarter of 2018. Partly offsetting these increases in earnings, was the absence of an $892 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation enacted in 2017.

Average production increased 2 percent in 2018 compared with 2017, primarily due to improved drilling and well performance, 8 MBOED from acquisitions in the Western North Slope and the Greater Kuparuk Area, and the startup of GMT-1 in the fourth quarter of 2018, partly offset by normal field decline.

<u>*Acquisitions*</u>
During the second quarter of 2018, we obtained regulatory approvals and completed a transaction with Anadarko Petroleum Corporation to acquire its 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. In 2018, our Alaska segment net production included 7 MBOED associated with the additional interest acquired. In addition, we now have 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery.

In December of 2018, we completed a transaction with BP to acquire their nonoperated interest in the Kuparuk Assets in Alaska, and to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. In 2018, our Alaska segment net production included 1 MBOED related to the additional interest acquired in the Greater Kuparuk Area. See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

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2017 vs. 2016

Alaska reported earnings of $1,466 million in 2017, compared with earnings of $319 million in 2016. The increase in earnings was mainly due to an $892 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation. Earnings were additionally improved due to higher crude oil prices in 2017. The earnings increase was partly offset by a $110 million after-tax impairment charge for the associated properties, plants and equipment of our small interest in the Point Thomson unit.

Average production increased 2 percent in 2017 compared with 2016, as the impact of normal field decline was more than offset by well performance in the Western North Slope, Greater Prudhoe and Greater Kuparuk areas and lower unplanned downtime.

Lower 48

	2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ 1,747**	(2,371)	(2,257)
Average Net Production			
Crude oil (MBD)	**229**	180	195
Natural gas liquids (MBD)	**69**	69	88
Natural gas (MMCFD)	**596**	898	1,219
Total Production (MBOED)	**397**	399	486
Average Sales Prices			
Crude oil (per barrel)	**$ 62.99**	47.36	37.49
Natural gas liquids (per barrel)	**27.30**	22.20	14.34
Natural gas (per thousand cubic feet)	**2.82**	2.73	2.20

The Lower 48 segment consists of operations located in the contiguous United States and the Gulf of Mexico. During 2018, the Lower 48 contributed 36 percent of our worldwide liquids production and 21 percent of our natural gas production.

2018 vs. 2017

Lower 48 reported earnings of $1,747 million in 2018, compared with a net loss of $2,371 million in 2017. Earnings increased primarily due to the absence of a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the marketing of our Barnett asset, recognized in the second quarter of 2017; higher realized crude oil and NGL prices; higher crude oil sales volumes; lower DD&A expense, primarily due to reserve additions and asset disposition impacts, partly offset by higher underlying volumes; lower exploration expenses and higher gain on dispositions related to noncore asset sales. The increase in earnings was partly offset by lower natural gas sales volumes, primarily due to the disposition of our interests in the San Juan Basin in 2017.

In 2018, our average realized crude oil price of $62.99 per barrel was 3 percent less than WTI of $64.92 per barrel. The differential was driven primarily by local market dynamics in the Gulf Coast, Bakken and Permian Basin.

Total average production decreased 1 percent in 2018 compared with 2017. The decrease was mainly attributable to normal field decline and disposition impacts related to interests sold in the San Juan Basin and other noncore assets. Adjusted for the impact of dispositions of 82 MBOED in 2017, underlying production increased approximately 25 percent in 2018 compared with 2017, primarily due to new production from unconventional assets in the Eagle Ford, Bakken and Permian Basin.

Asset Dispositions and Other Planned Disposition

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 for net proceeds of $105 million. 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. This transaction was recorded at fair value resulting in the recognition of a $44 million after-tax 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.

In the fourth quarter of 2018, we completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments. Production associated with the Barnett averaged 8 MBOED in 2018, of which approximately 55 percent was natural gas and 45 percent was natural gas liquids. After-tax impairment charges of $69 million were recognized during 2018.

In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in Golden Pass LNG Terminal and Golden Pass Pipeline located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal and pipeline capacity was held for receipt, storage and regasification of LNG purchased from QG3. As a result of entering into these agreements, we expect to recognize a loss of approximately $60 million in the first quarter of 2019. We have also entered into agreements to amend our contractual obligations for remaining use of the facilities. Completion of the sale is subject to regulatory approval.

See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Acquisition

We began acquiring early life-cycle acreage in the Austin Chalk in the fourth quarter of 2017 and have accumulated approximately 225,000 net acres at less than $1,000 per acre. We spud our first Austin Chalk well in late 2018 and plan to drill additional wells in 2019.

2017 vs. 2016

Lower 48 reported a loss of $2,371 million after-tax in 2017, compared with a loss of $2,257 million after-tax in 2016. The increase in loss was primarily due to proved property impairments in 2017, totaling $2.5 billion after-tax, for our interests in the San Juan Basin and the Barnett which were written down to fair value less costs to sell. Lower natural gas, crude oil and natural gas liquids sales volumes from asset dispositions and normal field decline further increased losses during the year.

The increase in losses was partly offset by:

- Lower DD&A expense, mainly resulting from a lower unit-of-production rate from reserve revisions, disposition impacts and lower volumes.
- A $689 million tax benefit, primarily related to the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation enacted in 2017.
- Higher realized crude oil, natural gas liquids and natural gas prices.
- Lower exploration expenses mainly due to:

  - Lower leasehold impairment expense, primarily the absence of 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds; $62 million for our Melmar leasehold and $52 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by an after-tax charge of $33 million for Shenandoah in deepwater Gulf of Mexico and an after-tax charge of $24 million for certain mineral assets, both in 2017.
  - Lower other exploration expenses, mainly due to the absence of a $95 million after-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract.
  - Lower dry hole costs primarily due to the absence of 2016 after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells, and $83 million for our Melmar well, partly offset by 2017 after-tax charges of $187 million for multiple wells in Shenandoah and $41 million for several wells in the Powder River Basin.

In 2017, our average realized crude oil price of $47.36 per barrel was 7 percent less than WTI of $50.90 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast and Bakken.

Total average production decreased 18 percent in 2017 compared with 2016. The decrease was mainly attributable to normal field decline and the disposition of our interests in the San Juan Basin, partly offset by new production, primarily from Eagle Ford and Bakken.

Asset Dispositions
On July 31, 2017, we completed the sale of our interests in the San Juan Basin for total proceeds comprised of $2.5 billion in cash after customary adjustments and 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 million British thermal units. During 2018, we recorded gains on dispositions for these contingent payments of $28 million.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

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Canada

	2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ 63**	2,564	(935)
Average Net Production			
Crude oil (MBD)	**1**	3	7
Natural gas liquids (MBD)	**1**	9	23
Bitumen (MBD)			
Consolidated operations	**66**	59	35
Equity affiliates	**-**	63	148
Total bitumen	**66**	122	183
Natural gas (MMCFD)	**12**	187	524
Total Production (MBOED)	**70**	165	300
Average Sales Prices			
Crude oil (per barrel)	**$ 48.73**	43.69	35.25
Natural gas liquids (per barrel)	**43.70**	21.51	14.82
Bitumen (dollars per barrel)*			
Consolidated operations	**22.29**	21.43	12.91
Equity affiliates	**-**	23.83	15.80
Total bitumen	**22.29**	22.66	15.27
Natural gas (per thousand cubic feet)	**1.00**	1.93	1.49

**Average prices for sales of bitumen produced during 2018 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 mainly consist of an oil sands development in the Athabasca region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2018, Canada contributed 8 percent of our worldwide liquids production and less than one percent of our worldwide natural gas production.

2018 vs. 2017

Canada operations reported earnings of $63 million in 2018 compared with $2,564 million in 2017. The decrease was mainly due to the absence of a $1.6 billion after-tax gain on the sale of our interest in the FCCL Partnership and western Canada gas assets and an associated $1.0 billion deferred tax benefit, and equity earnings in the FCCL Partnership. For additional information on the Canada disposition, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions and Note 7—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements.

Total average production decreased 95 MBOED in 2018 compared with 2017. The production decrease was primarily due to our 2017 Canada disposition, partly offset by strong well performance at Surmont.

Acquisition
In February 2018, we acquired approximately 34,500 net acres of undeveloped land in the Montney for a net purchase price of approximately $120 million. The additional acreage is adjacent to our existing position in the liquids-rich portion of the Montney.

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2017 vs. 2016

Canada operations reported earnings of $2,564 million in 2017, an increase of $3,499 million compared with 2016. The earnings increase was mainly due to an after-tax gain of $1.6 billion on the sale of certain Canadian assets, further discussed below, as well as the recognition of $1.0 billion in deferred tax benefits related to the capital gains component of our disposition and the recognition of previously unrealizable Canadian tax basis.

In addition to the items discussed above, earnings were further increased due to:

- Lower DD&A, mainly from disposition impacts.
- Lower dry hole costs, mainly due to the absence of 2016 combined after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.
- Higher realized prices across all commodities.
- A $114 million tax benefit related to our prior decision to exit Nova Scotia deepwater exploration.
- Lower production and operating expenses.
- Improved equity earnings, as improved prices and reduced DD&A more than offset the volume loss from our Canada disposition.

The earnings increase was partly offset by additional volume reductions from the disposition of our western Canada gas assets.

Total average production decreased 45 percent in 2017 compared with 2016. The production decrease was primarily due to the Canada disposition, partly offset by production rampup at Surmont.

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 Canadian dollars (CAD) for every $1 CAD by which the WCS quarterly average crude price exceeds $52 CAD per barrel. During 2018, we recorded gains on dispositions for these contingent payments of $95 million. See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Europe and North Africa

	2018	2017	2016
Net Income Attributable to ConocoPhillips (millions of dollars)	$ **1,866**	553	394
Average Net Production			
Crude oil (MBD)	**149**	142	122
Natural gas liquids (MBD)	**8**	8	7
Natural gas (MMCFD)	**503**	484	460
Total Production (MBOED)	**241**	230	205
Average Sales Prices			
Crude oil (dollars per barrel)	$ **70.71**	54.21	43.66
Natural gas liquids (per barrel)	**36.87**	34.07	22.62
Natural gas (per thousand cubic feet)	**7.65**	5.70	4.71

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The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea and Libya. In 2018, our Europe and North Africa operations contributed 19 percent of our worldwide liquids production and 18 percent of our natural gas production.

2018 vs. 2017

Earnings for Europe and North Africa operations of $1,866 million increased $1,313 million in 2018 compared to 2017. Earnings in 2018 included 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 United Kingdom. Earnings were also improved due to higher realized crude oil and natural gas prices and lower DD&A expense, primarily due to reserve additions.

Average production increased 5 percent in 2018, compared with 2017. The increase was mainly due to higher production in Libya and new wells online in Norway and the United Kingdom. These increases in production were partly offset by normal field decline and the final cessation of production in several producing gas fields in the Southern North Sea in the third quarter of 2018. Production associated with the Southern North Sea was 22 million cubic feet a day or 4 MBOED in 2018.

Dispositions
In the fourth quarter of 2018, we completed a transaction to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom and acquire their nonoperated interest in the Kuparuk Assets in Alaska. In 2018, our Europe and North Africa segment net production associated with the disposed 16.5 percent interest in the Clair Field was approximately 5 MBOED. We recognized a $774 million after-tax gain in the fourth quarter related to this transaction, as discussed above. See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

We are currently marketing our United Kingdom Business Unit.

2017 vs. 2016

Earnings for Europe and North Africa operations of $553 million increased 40 percent in 2017. The increase in earnings was primarily due to higher realized crude oil, natural gas and natural gas liquids prices. Earnings were additionally improved by lower DD&A, mainly due to reserve revisions; a $60 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the Tax Legislation; and a $41 million tax benefit in Norway.

The increase in earnings was partly offset by the absence of a 2016 net deferred tax benefit of $161 million resulting from a change in the U.K. tax rate and a lower credit to impairment in 2017, compared with 2016, reflecting the annual updates to ARO on fields at or nearing the end of life which were impaired in prior years. The earnings improvement was further reduced by a net deferred tax charge of $65 million in the U.K. resulting from updated assumptions regarding applicable tax rates.

Average production increased 12 percent in 2017, compared with 2016. The increase was mainly due to the resumption and rampup of production in Libya; improved drilling and well performance in Norway; new production from the Greater Britannia Area and Norway; and higher Norway gas offtake, partly offset by normal field decline.

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Asia Pacific and Middle East

	2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ 2,070**	(1,098)	209
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**89**	93	97
Equity affiliates	**14**	14	14
Total crude oil	**103**	107	111
Natural gas liquids (MBD)			
Consolidated operations	**3**	4	7
Equity affiliates	**7**	7	8
Total natural gas liquids	**10**	11	15
Natural gas (MMCFD)			
Consolidated operations	**626**	687	730
Equity affiliates	**1,031**	1,007	899
Total natural gas	**1,657**	1,694	1,629
Total Production (MBOED)	**389**	401	399
Average Sales Prices			
Crude oil (dollars per barrel)			
Consolidated operations	**$ 70.93**	54.38	42.23
Equity affiliates	**72.49**	54.76	44.11
Total crude oil	**71.14**	54.43	42.47
Natural gas liquids (dollars per barrel)			
Consolidated operations	**47.20**	41.37	29.00
Equity affiliates	**45.69**	38.74	31.13
Total natural gas liquids	**46.13**	39.75	30.11
Natural gas (dollars per thousand cubic feet)			
Consolidated operations	**6.15**	4.98	4.31
Equity affiliates	**6.06**	4.27	2.97
Total natural gas	**6.09**	4.55	3.57

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar. During 2018, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 60 percent of our natural gas production.

2018 vs. 2017

Asia Pacific and Middle East reported earnings of $2,070 million in 2018, compared with a loss of $1,098 million in 2017. The increase in earnings was mainly due to the absence of a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in 2017, higher realized commodity prices, and increased equity in earnings of affiliates, mainly due to higher LNG prices. See the “APLNG” section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on the 2017 impairment of our APLNG investment.

Average production decreased 3 percent in 2018, compared with 2017. The decrease was primarily due to unplanned downtime in Malaysia related to the rupture of a third-party pipeline which carries gas production from the Kebabangan gas field in Malaysia and normal field decline. This decrease was partly offset by new wells online at Malakai in Malaysia and an infill drilling program in China.

Asset Disposition
In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals. No production or reserve impacts are associated with the sale.

2017 vs. 2016

Asia Pacific and Middle East reported a loss of $1,098 million in 2017, compared with earnings of $209 million in 2016. The increase in loss was mainly due to a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in 2017. For additional information on our APLNG impairment, see the "APLNG" section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. Additionally, lower sales volumes in Indonesia, Australia and China further increased losses.

The increase in losses was partly offset by higher equity earnings, mainly as a result of higher commodity prices, increased sales volumes at APLNG and the absence of a 2016 deferred tax charge of $174 million resulting from the change of our APLNG tax functional currency. Higher realized crude oil and natural gas prices on non-equity volumes further reduced the loss.

Average production was essentially flat in 2017.

Other International

	2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$ 364	167	(16)

The Other International segment includes exploration activities in Colombia and Chile.

2018 vs. 2017

Other International operations reported earnings of $364 million in 2018, compared with earnings of $167 million in 2017. The increase in earnings was primarily due to recognizing $417 million after-tax in other income under a settlement agreement with PDVSA associated with an arbitration award issued by the ICC. Partly offsetting the increase in earnings, was the absence of a $320 million after-tax award from an arbitration settlement with The Republic of Ecuador in 2017. See Note 13—Contingencies and Commitments in the Notes to Consolidated Financial Statements, for additional information.

New Country Entrance
We received approval from Argentina's government in January 2019 for a 50 percent nonoperated interest in the El Turbio Este block in the Austral Basin.

2017 vs. 2016

Other International operations reported earnings of $167 million in 2017, compared with a loss of $16 million in 2016. The increase in earnings was primarily due to a $320 million after-tax International Centre for Settlement of Investment Disputes (ICSID) award from an arbitration with The Republic of Ecuador. Earnings were additionally increased due to lower rig stacking costs in Angola. The increase in earnings was partly

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offset by the absence of a $138 million gain in 2016 on the disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal, and a $45 million tax charge from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the Tax Legislation.

Corporate and Other

	Millions of Dollars		
	2018	2017	2016
Net Loss Attributable to ConocoPhillips			
Net interest	**$ (680)**	(739)	(980)
Corporate general and administrative expenses	**(91)**	(193)*	(147)*
Technology	**109**	20	50
Other	**(1,005)**	(1,224)*	(252)*
	$ (1,667)	(2,136)	(1,329)

**Certain amounts have been reclassified to reflect the adoption of ASU No. 2017-07. See Note 2—Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information.*

2018 vs. 2017

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased $59 million in 2018 compared with 2017, primarily due to less interest from lower debt balances, higher capitalized interest on projects, and an accrual reduction due to a transportation cost ruling by the FERC in the first quarter of 2018. Partly offsetting these impacts, were reduced tax benefits on interest expense following the Tax Legislation, which lowered the U.S. corporate income tax rate from 35 percent to 21 percent effective January 1, 2018, and a lower tax benefit due to higher interest from the fair market value method of apportioning interest expense in the United States.

Corporate general and administrative expenses include compensation programs and staff costs. These costs decreased by $102 million in 2018 compared with 2017, primarily due to lower staff expenses and costs associated with certain key employee compensation programs.

Technology includes our investment in new technologies or businesses, as well as licensing revenues. Activities are focused on tight oil reservoirs, LNG, oil sands and other production operations. Earnings from Technology increased by $89 million in 2018 compared with 2017, primarily due to higher licensing revenues. See Note 24—Sales and Other Operating Revenues, in the Notes to Consolidated Financial Statements, for additional information.

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. Losses in “Other” decreased by $219 million in 2018 compared with 2017, primarily due to the absence of an $813 million tax charge from the revaluation of deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation enacted in 2017; lower premiums on the early retirement of debt; partly offset by a $437 million unrealized loss on our Cenovus Energy common shares.

2017 vs. 2016

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased 25 percent in 2017 compared with 2016, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest as a result of reduced debt. Higher interest income further drove the decrease in net interest, which was partly offset by lower capitalized interest on projects.

Corporate general and administrative expenses which include pension settlement expenses and compensation program costs increased $46 million in 2017 compared with 2016, primarily due to higher costs associated with certain key employee compensation programs and staff expenses. See Note 2—Changes in Accounting Principles, in the Notes to Financial Statements, for additional information.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, LNG, oil sands and other production operations. Earnings from Technology were $20 million in 2017, compared with $50 million in 2016. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

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 and premiums incurred on the early retirement of debt. Losses in “Other” increased $972 million in 2017, mainly due to an $813 million tax charge from the revaluation of deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation and premiums on our early retirement of debt.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2018	2017	2016
Net cash provided by operating activities	**$ 12,934**	7,077	4,403
Cash and cash equivalents	**5,915**	6,325	3,610
Short-term debt	**112**	2,575	1,089
Total debt	**14,968**	19,703	27,275
Total equity	**32,064**	30,801	35,226
Percent of total debt to capital*	**32 %**	39	44
Percent of floating-rate debt to total debt	**5 %**	5	9

**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 2018, the primary uses of our available cash were $6,750 million to support our ongoing capital expenditures and investments program; $4,995 million to reduce debt; $2,999 million to repurchase our common stock; and $1,363 million to pay dividends on our common stock. During 2018, cash, cash equivalents, and restricted cash decreased by $385 million to $6,151 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 Sources of 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.

Significant Sources of Capital

Operating Activities
During 2018, cash provided by operating activities was $12,934 million, an 83 percent increase from 2017. The increase was primarily due to higher realized commodity prices and higher distributions from equity affiliates.

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 natural gas liquids. 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 1,283 MBOED in 2018. Full-year production excluding Libya averaged 1,242 MBOED in 2018 and is expected to be 1,300 to 1,350 MBOED in 2019. 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 2018, our reserve replacement, which included a net increase of 0.2 billion BOE from sales and purchases, was 147 percent. Increased crude oil reserves accounted for over 90 percent of the total change in reserves. Our organic reserve replacement, which excludes the impact of sales and purchases, was 109 percent in 2018. Approximately 33 percent of organic reserve additions are from Lower 48 unconventional assets, 29 percent from Alaska and 22 percent from Asia Pacific and Middle East.

In the five years ended December 31, 2018, our reserve replacement, which included a decrease of 2.1 billion BOE from sales and purchases, was negative 30 percent, reflecting the impact of asset dispositions and lower prices during that period. Our organic reserve replacement during the five years ended December 31, 2018, was 44 percent, reflecting development activities as well as lower prices during that period.

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 2019 capital budget, see the "2019 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. In 2018 and 2017, revisions increased reserves, while in 2016, revisions decreased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Investing Activities
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 received $253 million net proceeds for customary adjustments related to our transaction with BP for the disposition of a ConocoPhillips subsidiary holding a 16.5 percent interest in the Clair Field in the United Kingdom and the acquisition of the Kuparuk Assets. We received contingent payments of $95 million in relation to our 2017 Canada disposition to Cenovus Energy.

Proceeds from asset sales in 2017 were $13.9 billion. 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 $11.0 billion in cash after customary adjustments and 208 million Cenovus Energy common shares. We completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company. Total proceeds for the sale were $2.5 billion in cash after customary adjustments. We also completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

For additional information on our dispositions and investment in Cenovus common shares, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions and Note 7—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, and the Results of Operations section within Management's Discussion and Analysis.

Commercial Paper and Credit Facilities
In May 2018, we refinanced our revolving credit facility from a total aggregate principal amount of $6.75 billion to $6.0 billion with a new 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 United States. 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, 2018 or December 31, 2017. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at December 31, 2018 and December 31, 2017. 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, 2018.

In August 2018, Fitch upgraded our long-term debt rating from "A-" to "A" and adjusted their outlook for our debt from "positive" to "stable." In September 2018, Moody's Investors Services upgraded its rating on our long-term debt from "Baa1" to "A3" and adjusted its outlook for our debt from "positive" to "stable." In November 2018, Standard & Poor's upgraded our long-term debt rating from "A-" to "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, 2018 and 2017, we had direct bank letters of credit of $323 million and $338 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 U.S. Securities and Exchange Commission (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.

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Capital Requirements

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

Our debt balance at December 31, 2018, was $15.0 billion, a decrease of $4.7 billion from the balance at December 31, 2017. We achieved our stated debt target of $15 billion eighteen months earlier than the original target date of year-end 2019.

In 2018, we repaid the $250 million floating rate note due in 2018 at its natural maturity. We also redeemed or repurchased a total $4,450 million of debt, described below, incurring $208 million in net premiums above book value, which are reported in the “Other expenses” line on our consolidated income statement.

- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.
- 2.4% Notes due 2022 with principal of $1.0 billion (partial repurchase of $671 million).
- 3.35% Notes due 2024 with principal of $1.0 billion (partial repurchase of $574 million).
- 2.2% Notes due 2020 with principal of $500 million.
- 3.35% Notes due 2025 with principal of $500 million (partial repurchase of $301 million).
- 4.15% Notes due 2034 with principal of $500 million (partial repurchase of $254 million).
- 8.125% Notes due 2030 with principal of $600 million (partial repurchase of $210 million).
- 7.8% Notes due 2027 with principal of $300 million (partial repurchase of $97 million).
- 7.9% Notes due 2047 with principal of $100 million (partial repurchase of $40 million).
- 9.125% Notes due 2021 with principal of $150 million (partial repurchase of $27 million).
- 8.20% Notes due 2025 with principal of $150 million (partial repurchase of $16 million).
- 7.65% Notes due 2023 with principal of $88 million (partial repurchase of $10 million).

For more information on Debt, see Note 11—Debt, in the Notes to Consolidated Financial Statements.

On February 1, 2018, we announced an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share. The dividend was paid on March 1, 2018, to stockholders of record at the close of business on February 12, 2018. On May 4, 2018, we announced a quarterly dividend of $0.285 per share. The dividend was paid on June 1, 2018, to stockholders of record at the close of business on May 14, 2018. On July 11, 2018, we announced a quarterly dividend of $0.285 per share. The dividend was paid on September 4, 2018, to stockholders of record at the close of business on July 23, 2018. On October 5, 2018, we announced a 7 percent increase in the quarterly dividend to $0.305 per share. The dividend was paid on December 3, 2018, to stockholders of record at the close of business on October 15, 2018. On January 30, 2019, we announced a quarterly dividend of $0.305 cents per share, payable March 1, 2019, to stockholders of record at the close of business on February 11, 2019.

In late 2016, we initiated our current share repurchase program. As of June 30, 2018, we had announced authorization to repurchase a total of $6 billion of our common stock. We repurchased $3 billion in 2017 and $3 billion in 2018. On July 12, 2018, we announced an authorization of an additional $9 billion in share repurchases bringing the total program authorization to $15 billion. We expect to execute $3 billion of the remaining $9 billion of our share repurchase program in 2019. 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 111 million shares at a cost of $6.1 billion through December 31, 2018.

During the third quarter of 2017, we made a $600 million contribution to our domestic qualified pension plan, which is included in the “Other” line in the “Cash Flows From Operating Activities” section of our consolidated statement of cash flows. This additional contribution lowered our domestic pension deficit, thereby reducing 2018 premiums charged by the Pension Benefit Guaranty Corporation.

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Contractual Obligations

The table below summarizes our aggregate contractual fixed and variable obligations as of December 31, 2018:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Years 2–3	Years 4–5	After 5 Years
Debt obligations (a)	$ 14,191	33	159	987	13,012
Capital lease obligations (b)	777	79	155	143	400
Total debt	14,968	112	314	1,130	13,412
Interest on debt and other obligations	12,213	865	1,710	1,634	8,004
Operating lease obligations (c)	1,394	248	561	373	212
Purchase obligations (d)	9,703	4,000	1,854	1,422	2,427
Other long-term liabilities					
Pension and postretirement benefit contributions (e)	1,519	380	634	505	–
Asset retirement obligations (f)	7,908	378	672	681	6,177
Accrued environmental costs (g)	178	20	28	26	104
Unrecognized tax benefits (h)	115	115	(h)	(h)	(h)
Total	$ 47,998	6,118	5,773	5,771	30,336

(a) Includes $220 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) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(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 $3,412 million.

Purchase obligations of $5,169 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 2019 through 2023. For additional information related to expected benefit payments subsequent to 2023, 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.

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(h) Excludes unrecognized tax benefits of $966 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

	Millions of Dollars		
	2018	2017	2016
Alaska	**$ 1,298**	815	883
Lower 48	**3,184**	2,136	1,262
Canada	**477**	202	698
Europe and North Africa	**877**	872	1,020
Asia Pacific and Middle East	**718**	482	838
Other International	**6**	21	104
Corporate and Other	**190**	63	64
Capital Program	**$ 6,750**	4,591	4,869

Our capital expenditures and investments for the three-year period ended December 31, 2018, totaled $16.2 billion. The 2018 expenditures supported key exploration and developments, primarily:

- Development, appraisal and exploration activities in the Lower 48, including Eagle Ford, Bakken and Delaware in the Permian Basin.
- Leasehold acquisition and exploration, appraisal and development activities in Alaska related to the Western North Slope; development activities in the Greater Kuparuk Area and the Greater Prudhoe Area.
- Development activities in Europe, including the Greater Ekofisk Area, Clair Ridge and Aasta Hansteen.
- Leasehold acquisition, optimization of oil sands development and appraisal activities in liquids-rich plays in Canada.
- Continued development in China, Australia, Indonesia, and Malaysia, and exploration and appraisal activities in Malaysia.

2019 CAPITAL BUDGET

In December 2018, we announced a 2019 capital budget of $6.1 billion which includes funding for ongoing conventional and unconventional development drilling programs, major projects, exploration and appraisal activities, and base maintenance activities. We are planning to allocate approximately:

- 70 percent of our 2019 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford, Bakken and Delaware, as well as development drilling in Alaska, Canada and Europe.
- 15 percent of our 2019 capital expenditures budget to maintain base production and corporate expenditures.
- 10 percent of our 2019 capital expenditures budget to major projects. These funds will focus on major projects in Alaska, China, Australia, Europe and Malaysia.
- 5 percent of our 2019 capital expenditures budget to new exploration activity, primarily in Alaska and the Lower 48.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the "Oil and Gas Operations" section.

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, 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 United States.
- 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 United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States 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 the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, 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, 2018, there were 14 sites around the United States 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 $442 million in 2018 and are expected to be about $530 million per year in 2019 and 2020. Capitalized environmental costs were $191 million in 2018 and are expected to be about $240 million per year in 2019 and 2020.

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, 2018, our balance sheet included total accrued environmental costs of $178 million, compared with $180 million at December 31, 2017, 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 greenhouse gas (GHG) reduction.

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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 European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2018 was approximately $5.6 million (net share 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 2018 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 2018 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 $0.6 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 United States announced its intention to withdraw from the Paris Agreement, there is no guarantee that the commitments made by the United States will not be implemented, in whole or in part, by U.S. state and local governments or by major corporations headquartered in the United States.

In the United States, 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 Practice covering the assessment and registering of significant and high sustainable development risks based on their consequence and likelihood of occurrence. A corporate Climate Change Action Plan has been developed to track 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.

The company uses a range of estimated future costs of GHG emissions for internal planning purposes, including an estimated market cost of GHG emissions of $40 per metric tonne applied beginning in the year 2024 to evaluate certain future projects and opportunities. 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 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 2017 and 2018, cities, counties, a state government, and a trade association 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.

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.

NEW ACCOUNTING STANDARDS

In February 2016, the FASB issued Accounting Standards Update (ASU) No. 2016-02, "Leases" (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, "Leases" (FASB ASC Topic 840), and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements.

ASU No. 2016-02 was amended in January 2018 by the provisions of ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842" (ASU No. 2018-01), and in July 2018 by the provisions of ASU No. 2018-10, "Codification Improvements to Topic 842, Leases" (ASU No. 2018-10). In addition, ASU No. 2016-02 was further amended in July 2018 by the provisions of ASU No. 2018-11, "Targeted Improvements" (ASU No. 2018-11), and in December 2018 by the provisions of ASU No. 2018-20, "Narrow-Scope Improvements for Lessors" (ASU No. 2018-20).

ASU No. 2018-11 sets forth certain additional practical expedients for lessors and provides entities with an option to apply the provisions of ASU No. 2016-02, as amended, to leasing arrangements existing at or entered into after the ASU's effective date of adoption (the "Optional Transition Method"). Entities that elect to utilize the Optional Transition Method would not apply the provisions of ASU No. 2016-02, as amended, to comparative periods presented in the financial statements.

We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, utilizing the Optional Transition Method. Accordingly, the comparative periods presented in the financial statements prior to January 1, 2019, will be presented pursuant to the existing requirements of FASB ASC Topic 840 and not be adjusted upon the adoption of the ASU. We also expect to utilize the package of optional transition-related practical expedients set forth by ASU No. 2016-02, as amended, which permit entities to not reassess upon the adoption of the ASU certain historical conclusions regarding lease contract identification and classification, as well as the historical accounting treatment of initial direct costs (the "Package of Optional Practical Expedients"). For lease arrangements containing both lease and non-lease components, we will adopt the optional practical expedient to not separate lease components from non-lease components for all new or modified leases executed on or after the effective date of the ASU, subject to making any elections for leases after the effective date in new asset classes. Furthermore, we do not expect to record assets and liabilities on our consolidated balance sheet for new or existing lease arrangements with terms of 12 months or less.

The expected impact of the adoption of ASU No. 2016-02, as amended, relates primarily to our balance sheet, resulting from the initial recognition of lease liabilities and corresponding right-of-use assets for our existing population of operating leases, as well as enhanced disclosure of our leasing arrangements. We expect to recognize on our consolidated balance sheet approximately $1 billion of operating lease liabilities and corresponding right-of-use assets upon the adoption of ASU No. 2016-02, as amended. We have implemented a third-party lease accounting software solution to facilitate the ongoing accounting and financial reporting requirements of the ASU and also expect the adoption of the ASU to result in certain changes being made to our existing accounting policies and systems, business processes, and internal controls.

While our evaluation of ASU No. 2016-02, as amended, and related implementation activities approach completion, we continue to monitor proposals issued by the FASB to clarify the ASU. For additional information, see Note 26—New Accounting Standards, in the Notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles 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 discussions of contingencies and 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 discovered on the prospect.

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 2018, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $468 million and the accumulated impairment reserve was $153 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 71 percent, and the weighted-average amortization period was approximately two years. If that judgmental percentage were to be raised by 5 percent across all calculations, before-tax leasehold impairment expense in 2019 would increase by approximately $7 million. At year-end 2018, the remaining $3.6 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 $2.6 billion is concentrated in 10 major development areas, the majority of which are not expected to move to proved properties in 2019. 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 2018, total suspended well costs were $856 million, compared with $853 million at year-end 2017. 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 production sharing contracts, 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 2018, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $37 billion and the DD&A recorded on these assets in 2018 was approximately $5.5 billion. The estimated proved developed reserves for our consolidated operations were 3.0 billion BOE at the end of 2017 and 3.3 billion BOE at the end of 2018. 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 2018 would have increased by an estimated $611 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 exploration and production 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 United States 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 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,000 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $110 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $40 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 elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, 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.”

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 natural gas liquids 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 natural gas liquids, 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 exploration and production 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 natural gas liquids.
- 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, 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, natural gas liquids and any materials or products (such as aluminum and steel) used in the operation of our business.
- Reduced demand for our products or the use of competing energy products, including alternative energy sources.
- Substantial investment in and development of 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 environmental regulations.
- 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 natural gas liquids pricing, regulation or taxation; the impact of and uncertainty surrounding the United Kingdom's decision to withdraw from the European Union; 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 in the oil and gas exploration and production 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 inability to collect payments when due under our ICC settlement agreement with PDVSA.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A—Risk Factors in this 2018 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, 2018, 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, 2018 and 2017, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk
The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of 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 financial instruments is estimated based on quoted market prices.

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Expected Maturity Date	Millions of Dollars Except as Indicated					
	Debt					
	Fixed Rate Maturity	Average Interest Rate		Floating Rate Maturity	Average Interest Rate	
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**		
Year-End 2017						
2018	$ 2,250	3.31	%	$ 250	1.75	%
2019	23	-		-	-	
2020	-	-		-	-	
2021	150	9.13		-	-	
2022	1,014	2.45		500	2.32	
Remaining years	14,207	6.00		283	1.70	
Total	$ 17,644			$ 1,033		
Fair value	$ 21,402			$ 1,033		

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, 2018 and 2017, 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, 2018 and 2017, we had outstanding foreign currency zero-cost collars buying the right to sell $1.25 billion Canadian dollars (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, 2018 and December 31, 2017, was a before-tax gain of $6 million and a before-tax loss of $9 million, respectively. Based on an adverse hypothetical 10 percent change in the December 2018 and December 2017 exchange rate, this would result in an additional before-tax loss of $17 million and $74 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.

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The gross notional and fair market values of these positions at December 31, 2018 and 2017, were as follows:

	In Millions				
Foreign Currency Exchange Derivatives	Notional*			Fair Market Value**	
	2018		2017	**2018**	2017
Sell U.S. dollar, buy British pound	USD	**805**	-	**(5)**	-
Sell Canadian dollar, buy U.S. dollar	CAD	**1,250**	1,250	**6**	(9)
Buy Canadian dollar, sell U.S. dollar	CAD	**8**	25	**-**	1
Sell British pound, buy Norwegian krone	GBP	**9**	-	**-**	-
Sell British pound, buy euro	GBP	**12**	1	**-**	-

**Denominated in U.S. dollars (USD), Canadian dollars (CAD) and British pound (GBP) .*
***Denominated in U.S. dollars.*

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

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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, 2018. 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, 2018.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2018, and their report is included herein.

/s/ Ryan M. Lance	/s/ Don E. Wallette, Jr.
Ryan M. Lance	**Don E. Wallette, Jr.**
Chairman and Chief Executive Officer	Executive Vice President and Chief Financial Officer

February 19, 2019

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 as of December 31, 2018 and 2017, and 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, 2018, 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 referred to above present fairly, in all material respects, the financial position of ConocoPhillips at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with 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), ConocoPhillips' internal control over financial reporting as of December 31, 2018, 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 19, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of ConocoPhillips' management. Our responsibility is to express an opinion on ConocoPhillips' 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 ConocoPhillips 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.

/s/ Ernst & Young LLP

We have served as ConocoPhillips' auditor since 1949.

Houston, Texas
February 19, 2019

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, 2018, 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, 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 as of December 31, 2018 and 2017, and 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, 2018, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) of ConocoPhillips and our report dated February 19, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

ConocoPhillips' 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 ConocoPhillips' 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 ConocoPhillips 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

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Consolidated Income Statement **ConocoPhillips**

Years Ended December 31

	Millions of Dollars		
	2018	2017*	2016*
Revenues and Other Income			
Sales and other operating revenues	$ **36,417**	29,106	23,693
Equity in earnings of affiliates	**1,074**	772	52
Gain on dispositions	**1,063**	2,177	360
Other income	**173**	529	255
Total Revenues and Other Income	**38,727**	32,584	24,360
Costs and Expenses			
Purchased commodities	**14,294**	12,475	9,994
Production and operating expenses	**5,213**	5,162	5,643
Selling, general and administrative expenses	**401**	427	473
Exploration expenses	**369**	934	1,912
Depreciation, depletion and amortization	**5,956**	6,845	9,062
Impairments	**27**	6,601	139
Taxes other than income taxes	**1,048**	809	739
Accretion on discounted liabilities	**353**	362	425
Interest and debt expense	**735**	1,098	1,245
Foreign currency transaction (gains) losses	**(17)**	35	(19)
Other expenses	**375**	451	277
Total Costs and Expenses	**28,754**	35,199	29,890
Income (loss) before income taxes	**9,973**	(2,615)	(5,530)
Income tax provision (benefit)	**3,668**	(1,822)	(1,971)
Net income (loss)	**6,305**	(793)	(3,559)
Less: net income attributable to noncontrolling interests	**(48)**	(62)	(56)
Net Income (Loss) Attributable to ConocoPhillips	$ **6,257**	(855)	(3,615)
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*			
Basic	$ **5.36**	(0.70)	(2.91)
Diluted	**5.32**	(0.70)	(2.91)
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,166,499**	1,221,038	1,245,440
Diluted	**1,175,538**	1,221,038	1,245,440

**Certain amounts have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07. See Note 2—Changes in Accounting Principles, for additional information.*
See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income ConocoPhillips

Years Ended December 31

	Millions of Dollars		
	2018	2017	2016
Net Income (Loss)	**$ 6,305**	(793)	(3,559)
Other comprehensive income (loss)			
Defined benefit plans			
Prior service credit (cost) arising during the period	**(7)**	2	23
Reclassification adjustment for amortization of prior service credit included in net loss	**(40)**	(38)	(35)
Net change	**(47)**	(36)	(12)
Net actuarial gain (loss) arising during the period	**(150)**	19	(481)
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)	**279**	247	309
Net change	**129**	266	(172)
Nonsponsored plans*	**(1)**	(2)	2
Income taxes on defined benefit plans	**(42)**	(81)	78
Defined benefit plans, net of tax	**39**	147	(104)
Unrealized holding loss on securities	**-**	(58)	-
Unrealized loss on securities, net of tax**	**-**	(58)	-
Foreign currency translation adjustments	**(645)**	586	153
Reclassification adjustment for gain included in net loss	**-**	-	5
Income taxes on foreign currency translation adjustments	**3**	-	-
Foreign currency translation adjustments, net of tax	**(642)**	586	158
Other Comprehensive Income (Loss), Net of Tax	**(603)**	675	54
Comprehensive Income (Loss)	**5,702**	(118)	(3,505)
Less: comprehensive income attributable to noncontrolling interests	**(48)**	(62)	(56)
Comprehensive Income (Loss) Attributable to ConocoPhillips	**$ 5,654**	(180)	(3,561)

* *Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
** *See Note 2—Changes in Accounting Principles and Note 20—Accumulated Other Comprehensive Loss, for additional information relating to the adoption of ASU No. 2016-01.*

See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet ConocoPhillips

At December 31	Millions of Dollars	
	2018	2017
Assets		
Cash and cash equivalents	**$ 5,915**	6,325
Short-term investments	**248**	1,873
Accounts and notes receivable (net of allowance of $25 million in 2018 and $4 million in 2017)	**3,920**	4,179
Accounts and notes receivable—related parties	**147**	141
Investment in Cenovus Energy	**1,462**	1,899
Inventories	**1,007**	1,060
Prepaid expenses and other current assets	**575**	1,035
Total Current Assets	**13,274**	16,512
Investments and long-term receivables	**9,329**	9,599
Loans and advances—related parties	**335**	461
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $64,899 million in 2018 and $64,748 million in 2017)	**45,698**	45,683
Other assets	**1,344**	1,107
Total Assets	**$ 69,980**	73,362
Liabilities		
Accounts payable	**$ 3,863**	4,009
Accounts payable—related parties	**32**	21
Short-term debt	**112**	2,575
Accrued income and other taxes	**1,320**	1,038
Employee benefit obligations	**809**	725
Other accruals	**1,259**	1,029
Total Current Liabilities	**7,395**	9,397
Long-term debt	**14,856**	17,128
Asset retirement obligations and accrued environmental costs	**7,688**	7,631
Deferred income taxes	**5,021**	5,282
Employee benefit obligations	**1,764**	1,854
Other liabilities and deferred credits	**1,192**	1,269
Total Liabilities	**37,916**	42,561
Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2018—1,791,637,434 shares; 2017—1,785,419,175 shares)		
Par value	**18**	18
Capital in excess of par	**46,879**	46,622
Treasury stock (at cost: 2018—653,288,213 shares; 2017—608,312,034 shares)	**(42,905)**	(39,906)
Accumulated other comprehensive loss	**(6,063)**	(5,518)
Retained earnings	**34,010**	29,391
Total Common Stockholders' Equity	**31,939**	30,607
Noncontrolling interests	**125**	194
Total Equity	**32,064**	30,801
Total Liabilities and Equity	**$ 69,980**	73,362

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows ConocoPhillips

Years Ended December 31	Millions of Dollars		
	2018	2017	2016
Cash Flows From Operating Activities			
Net income (loss)	**$ 6,305**	(793)	(3,559)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**5,956**	6,845	9,062
Impairments	**27**	6,601	139
Dry hole costs and leasehold impairments	**95**	566	1,184
Accretion on discounted liabilities	**353**	362	425
Deferred taxes	**283**	(3,681)	(2,221)
Undistributed equity earnings	**152**	(232)	299
Gain on dispositions	**(1,063)**	(2,177)	(360)
Other	**191**	(429)	(85)
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**235**	(886)	820
Decrease (increase) in inventories	**86**	(55)	44
Decrease (increase) in prepaid expenses and other current assets	**(55)**	69	105
Increase (decrease) in accounts payable	**(52)**	265	(524)
Increase (decrease) in taxes and other accruals	**421**	622	(926)
Net Cash Provided by Operating Activities	**12,934**	7,077	4,403
Cash Flows From Investing Activities			
Capital expenditures and investments	**(6,750)**	(4,591)	(4,869)
Working capital changes associated with investing activities	**(68)**	132	(331)
Proceeds from asset dispositions	**1,082**	13,860	1,286
Net sales (purchases) of short-term investments	**1,620**	(1,790)	(51)
Collection of advances/loans—related parties	**119**	115	108
Other	**154**	36	(2)
Net Cash Provided by (Used in) Investing Activities	**(3,843)**	7,762	(3,859)
Cash Flows From Financing Activities			
Issuance of debt	**-**	-	4,594
Repayment of debt	**(4,995)**	(7,876)	(2,251)
Issuance of company common stock	**121**	(63)	(63)
Repurchase of company common stock	**(2,999)**	(3,000)	(126)
Dividends paid	**(1,363)**	(1,305)	(1,253)
Other	**(123)**	(112)	(137)
Net Cash Provided by (Used in) Financing Activities	**(9,359)**	(12,356)	764
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	**(117)**	232	(66)
Net Change in Cash, Cash Equivalents and Restricted Cash	**(385)**	2,715	1,242
Cash, cash equivalents and restricted cash at beginning of period	**6,536** *	3,610	2,368
Cash, Cash Equivalents and Restricted Cash at End of Period	**$ 6,151**	6,325	3,610

** Restated to include $211 million of restricted cash at January 1, 2018. See Note 2—Changes in Accounting Principles for additional information relating to the adoption of ASU No. 2016-18.*

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.

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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, 2015	$ 18	46,357	(36,780)	(6,247)	36,414	320	40,082
Net income (loss)					(3,615)	56	(3,559)
Other comprehensive income				54			54
Dividends paid ($1.00/share of common stock)					(1,253)		(1,253)
Repurchase of company common stock			(126)				(126)
Distributions to noncontrolling interests and other						(124)	(124)
Distributed under benefit plans		150					150
Other					2		2
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/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 ($1.16/share of common stock)					**(1,363)**		**(1,363)**
Repurchase of company common stock			**(2,999)**				**(2,999)**
Distributions to noncontrolling interests and other						**(121)**	**(121)**
Distributed under benefit plans		**257**					**257**
Changes in Accounting Principles*				**58**	**(278)**		**(220)**
Other					**3**	**4**	**7**
December 31, 2018	**$ 18**	**46,879**	**(42,905)**	**(6,063)**	**34,010**	**125**	**32,064**

**See Note 2—Changes in Accounting Principles for additional information.*
See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements ConocoPhillips

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 income 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 United States 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, liquified natural gas (LNG), natural gas liquids 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**—Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

- **Inventories**—We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Our commodity-related inventories are recorded at cost primarily using the last-in, first-out (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 first-in, first-out (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 properties, plants and equipment (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 exploration and production 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.

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- **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 depreciation, depletion and amortization (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 Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2014-09, "Revenue from Contracts with Customers," and its amendments issued by the provisions of ASU No. 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," ASU No. 2016-10, "Identifying Performance Obligations and Licensing," ASU No. 2016-12, "Narrow-Scope Improvements and Practical Expedients," and ASU No. 2016-20, "Technical Corrections and Improvements to Topic 606, Revenue From Contracts with Customers," collectively Accounting Standards Codification (ASC) Topic 606, "Revenue from Contracts with Customers," (ASC Topic 606) beginning January 1, 2018. ASC Topic 606 outlines a single comprehensive model for an entity to use in accounting for revenue arising from all contracts with customers except where revenues are in scope of another accounting standard. The ASU superseded the revenue recognition requirements in ASC Topic 605, "Revenue Recognition," and most industry-specific guidance. ASC Topic 606 sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity is required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods and services. ASC Topic 606 also requires certain additional revenue-related disclosures. The adoption of ASC Topic 606 did not have a material impact on our consolidated financial statements. See Note 24—Sales and Other Operating Revenues for additional information related to this ASC.

We adopted the provisions of FASB ASU No. 2016-01, "Recognition and Measurement of Financial Assets and Liabilities," (ASU No. 2016-01) beginning January 1, 2018. The ASU, among other things, requires an entity to record the changes in fair value of equity investments, other than investments accounted for using the equity method, within net income. Under this ASU, an entity is no longer able to recognize unrealized holding gains and losses on equity securities in other comprehensive income and instead must recognize them in the income statement. See Note 7—Investment in Cenovus Energy and Note 20—Accumulated Other Comprehensive Loss for additional information relating to this ASU.

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The cumulative effect of the changes made to our consolidated balance sheet at January 1, 2018, for the adoption of ASC Topic 606 and ASU No. 2016-01 were as follows:

	Millions of Dollars			
	December 31 2017	ASC Topic 606 Adjustments	ASU No. 2016-01 Adjustments	**January 1 2018**
Liabilities				
Other accruals	$ 1,029	104	-	**1,133**
Total current liabilities	9,397	104	-	**9,501**
Deferred income taxes	5,282	(31)	-	**5,251**
Other liabilities and deferred credits	1,269	147	-	**1,416**
Total liabilities	42,561	220	-	**42,781**
Equity				
Accumulated other comprehensive loss	$ (5,518)	-	58	**(5,460)**
Retained earnings	29,391	(220)	(58)	**29,113**
Total common stockholders' equity	30,607	(220)	-	**30,387**
Total equity	30,801	(220)	-	**30,581**

For discussion of adjustments for ASU No. 2016-01 and ASC Topic 606, see Note 7—Investment in Cenovus Energy and Note 24—Sales and Other Operating Revenues, respectively.

We adopted the provisions of FASB ASU No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost," beginning January 1, 2018. We retrospectively applied the presentation of service cost separate from the other components of net periodic costs. The interest cost, expected return on plan assets, amortization of prior service cost/credit, recognized net actuarial loss/gain, settlement expense, curtailment loss/gain, and special termination benefits have been reclassified from the "Production and operating expenses," "Selling, general and administrative expenses," and "Exploration expenses" lines to the "Other expenses" line on our consolidated income statement. We elected to apply the practical expedient which allows us to reclassify amounts disclosed previously in the employee benefit plans footnote as the basis for applying retrospective presentation for prior comparative periods as it is impracticable to determine the disaggregation of the cost components for amounts capitalized and amortized in those periods. On a prospective basis, the other components of net periodic benefit costs will not be included in amounts capitalized in inventory or PP&E.

The effect of the retrospective presentation change related to the net periodic benefit cost of our defined benefit pension and other postretirement employee benefits plans on our consolidated income statement was as follows:

	Millions of Dollars		
	Previously Reported	Effect of Change Higher/(Lower)	As Revised
Year Ended December 31, 2017			
Production and operating expenses	$ 5,173	(11)	5,162
Selling, general and administrative expenses	561	(134)	427
Exploration expenses	938	(4)	934
Other expenses	302	149	451
Year Ended December 31, 2016			
Production and operating expenses	$ 5,667	(24)	5,643
Selling, general and administrative expenses	723	(250)	473
Exploration expenses	1,915	(3)	1,912
Other expenses	-	277	277

We adopted the provisions of FASB ASU No. 2016-15, “Classification of Certain Cash Receipts and Cash Payments,” beginning January 1, 2018. This ASU clarifies how certain cash receipts and cash payments should be classified and presented in the statement of cash flows. We have made an accounting policy election to classify distributions received from equity method investees using the nature of the distribution approach which classifies distributions received from investees as either cash inflows from operating activities or cash inflows from investing activities in the statement of cash flows based on the nature of the activities of the investee that generated the distribution. The impact of adopting this ASU was not material to prior presented periods.

We adopted the provisions of FASB ASU No. 2016-18, “Restricted Cash,” beginning January 1, 2018. This ASU requires amounts deemed restricted cash to be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, and presentation should permit a reconciliation when cash, cash equivalents and restricted cash are presented in more than one line item on the balance sheet. We have amounts deposited in statutory bank accounts in certain countries to satisfy asset retirement obligations (ARO). These amounts are deemed restricted cash and are included in the “Other assets” line of our consolidated balance sheet. This standard is required to be applied retrospectively to all periods presented, but the impact in those periods was not material.

Note 3—Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

Australia Pacific LNG Pty Ltd (APLNG)
APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2018, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 6—Investments, Loans and Long-Term Receivables, and Note 12—Guarantees, for additional information.

Marine Well Containment Company, LLC (MWCC)
MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. 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 and exercise significant influence through our permanent seat on the ten-member Executive Committee responsible for overseeing the affairs of MWCC. In 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. 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.

At December 31, 2018, the book value of our equity method investment in MWCC was $130 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.

Note 4—Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2018	2017
Crude oil and natural gas	**$ 432**	512
Materials and supplies	**575**	548
	$ 1,007	1,060

Inventories valued on the LIFO basis totaled $292 million and $341 million at December 31, 2018 and 2017, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $75 million and $124 million at December 31, 2018 and December 31, 2017, respectively. In 2018, liquidation of LIFO inventory values decreased the net income attributable to ConocoPhillips by $6 million.

Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions

Assets Held for Sale
In 2018, we signed a definitive agreement to sell an office building for $90 million, and the held for sale criteria were met in the fourth quarter of 2018. As of December 31, 2018, the building had a carrying value of $90 million which we reclassified to “Prepaid expenses and other current assets” on our consolidated balance sheet. The transaction closed in January 2019. The building is included in our Corporate and other segment.

2018
Assets Sold
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.

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, $566 million and $66 million for the years ended December 31, 2018, 2017 and 2016, 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 a 16.5 percent interest in the BP-operated Clair Field in the United Kingdom. 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 16.5 percent 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 percent interest in the Clair Field, including the recognized gain, were $748 million. The before-tax losses associated with our 16.5 percent interest in the Clair Field were $0.4 million and $8 million for the years ended December 31, 2017 and 2016, respectively. 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.

Other Planned Dispositions
In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals. The Greater Sunrise Fields are included in our Asia Pacific and Middle East segment.

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 located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal and pipeline capacity are used for receipt, storage and regasification of LNG purchased from Qatar Liquefied Gas Company Limited (QG3) and transportation of the regasified natural gas. As a result of entering into these agreements, we expect to recognize a loss of approximately $60 million in the first quarter of 2019. We have also entered into agreements to amend our contractual obligations for retaining use of the facilities. Completion of the sale is subject to regulatory approval.

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 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 asset retirement obligations, and a $100 million decrease to net working capital. The Kuparuk Assets are included in our Alaska segment.

2017
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 New York Stock Exchange. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (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 and $89 million for the years ended December 31, 2017 and 2016, respectively. We reported before-tax losses of $26 million and $572 million for the western Canada gas producing properties for the same periods, respectively. In 2018, we recorded a gain on dispositions for these contingent payments of $95 million.

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 million British thermal units. In 2018, we recorded a gain on dispositions for these contingent payments of $28 million. 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 losses associated with our interests in the San Juan Basin, including both the $3.3 billion impairment and $22 million loss on disposition noted above, were $3.2 billion and $239 million for the years ended December 31, 2017 and 2016, respectively. 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 before-tax losses for the Panhandle properties of $14 million and $21 million for the years ended December 31, 2017 and 2016, respectively. The Panhandle results were reported in our Lower 48 segment.

2016
In April 2016, we sold our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet for $134 million, net of settlement of gas imbalances and customary adjustments, and recognized a gain on disposition of $56 million. At the time of disposition, the net carrying value of our Beluga River Unit interest, which was included in the Alaska segment, was $78 million, consisting primarily of $100 million of PP&E and $19 million of AROs.

In October 2016, we completed an asset exchange with Bonavista Energy in which we gave up approximately 141,000 net acres of noncore developed properties in central Alberta in exchange for approximately 40,000 net acres of primarily undeveloped properties in northeast British Columbia. The fair value of the transaction was determined to be approximately $69 million and an impairment of $57 million was recognized in the third quarter of 2016 when the assets were considered held for sale, to reduce the carrying value to fair value. A loss on disposition of approximately $1 million was recognized upon completion of the transaction. The divested properties were included in the Canada segment.

Also in October 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal for $442 million and recognized a gain on disposition of $146 million. At the time of disposition, the carrying value of our interest was $286 million, which was primarily PP&E. Senegal results of operations were reported within our Other International segment.

In November 2016, we completed the sale of our 40 percent interest in South Natuna Sea Block B for $225 million and recognized a loss on disposition of $26 million. Our interest in Block B was included in the Asia Pacific and Middle East segment. In 2016, we recognized an impairment of $42 million at the time it was considered held for sale to reduce the carrying value to fair value. At the time of the disposition, the carrying value of our interest was approximately $251 million, which included primarily $154 million of PP&E, $178 million of accounts receivable, $25 million of inventory, $54 million of deferred tax assets, $130 million of accounts payable and other accruals, and $38 million of employee benefit obligations.

In December 2016, we completed the sale of certain mineral and non-mineral fee lands in northeastern Minnesota, which were included in the Lower 48 segment, for $148 million and recorded a gain on disposition of $4 million. The majority of the assets sold were acquired during the fourth quarter of 2016 as a result of ConocoPhillips holding a reversionary interest in the Greater Northern Iron Ore Properties Trust (the Trust), a grantor trust that owned mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. In November 2016, upon completion of the wind-down period, documents memorializing ConocoPhillips' ownership of certain Trust property, including all of the Trust's mineral properties and active leases, were delivered to us and we recognized the fair value of the net assets resulting in a gain of $88 million recorded in the "Other income" line on our consolidated income statement. At the time of the disposition, the carrying value of our interests, which included the assets obtained from the Trust, consisted of $144 million of PP&E.

Note 6—Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2018	2017
Equity investments	**$ 9,005**	9,129
Loans and advances—related parties	**335**	461
Long-term receivables	**238**	375
Other investments	**86**	95
	$ 9,664	10,060

Equity Investments
Affiliated companies in which we had a significant equity investment at December 31, 2018, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent)—to develop coalbed methane production 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		
	2018	2017	2016
Revenues	$ **11,654**	11,554	10,149
Income (loss) before income taxes	**3,660**	(2,875)	660
Net income (loss)	**3,244**	(1,431)	799

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

	Millions of Dollars	
	2018	2017
Current assets	$ **3,285**	2,920
Noncurrent assets	**41,563**	42,693
Current liabilities	**2,625**	2,453
Noncurrent liabilities	**23,874**	25,522

Our share of income taxes incurred directly by an equity company 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, 2018, retained earnings included $27 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,226 million, $605 million and $398 million in 2018, 2017 and 2016, respectively.

APLNG

APLNG is focused on coalbed methane 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 coalbed methane 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, 2018, 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. Interest payments are scheduled to commence in March 2019 and principal payments in September 2023, with bi-annual payments due on the facility until September 2030. At December 31, 2018, a balance of $7.2 billion was outstanding on the facilities.

In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for both trains, which removed the remaining guarantee.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 3—Variable Interest Entities (VIEs) for additional information.

On July 1, 2016, APLNG changed its tax functional currency from Australian dollar to U.S. dollar and translated all APLNG assets and liabilities into U.S. dollar, utilizing the exchange rate as of that date. As a result of this change, we recorded a reduction to our investment in APLNG for the deferred tax effect of $174 million in the “Equity in earnings of affiliates” line of our consolidated income statement.

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, 2018, the carrying value of our equity method investment in APLNG was $7,522 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $7,231 million, resulting in a basis difference of $291 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 2018, 2017 and 2016 was after-tax expense of $44 million, $100 million and $92 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—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions and Note 7—Investment in Cenovus Energy.

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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 $461 million as described below under “Loans and Long-Term Receivables.” At December 31, 2018, the book value of our equity method investment in QG3, excluding the project financing, was $921 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States. In January 2019, we entered into agreements to sell our ownership interests in Golden Pass LNG Terminal and Golden Pass Pipeline. For additional information, see Note 5—Assets Held for Sale, Sold or Acquired and Other Planned 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, 2018, significant loans to affiliated companies include $461 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 approximated 16.9 percent of issued and outstanding Cenovus Energy common stock at closing. See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions for additional information on the Canada disposition. At closing of the sale, 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 New York Stock Exchange.

We adopted the provisions of ASU No. 2016-01, beginning January 1, 2018, using the cumulative-effect approach. Results for reporting periods beginning January 1, 2018, are presented under ASU No. 2016-01 with all changes in the fair value of our equity securities reflected within the “Other income” line of our consolidated income statement and within the “Other” line in the “Cash Flows From Operating Activities” section of our consolidated statement of cash flows. Prior period amounts are not adjusted under the cumulative-effect method of adopting ASU No. 2016-01. See Note 2—Changes in Accounting Principles and Note 20—Accumulated Other Comprehensive Loss for the effect on our consolidated balance sheet and the line items that have been impacted by the adoption of this standard.

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The cumulative effect of applying the standard was the reclassification of accumulated unrealized holding losses of $58 million, recognized in 2017, related to our investment in Cenovus Energy from accumulated other comprehensive loss to retained earnings.

Our investment is carried at fair value of $1.46 billion as of December 31, 2018, reflecting the closing price of Cenovus Energy shares on the New York Stock Exchange of $7.03 per share, a decrease from its fair value of $1.90 billion at year-end 2017. For the year ended December 31, 2018, we recorded a before-tax unrealized loss of $437 million, related to the shares held at the reporting date. See Note 15—Fair Value Measurement, 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 2018, 2017 and 2016:

	Millions of Dollars		
	2018	2017	2016
Beginning balance at January 1	**$ 853**	1,063	1,260
Additions pending the determination of proved reserves	**140**	118	225
Reclassifications to proved properties	**(37)**	(66)	(27)
Sales of suspended wells	**(93)**	-	(247)
Charged to dry hole expense	**(7)**	(262)	(148)
Ending balance at December 31	**$ 856**	853	1,063

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

	Millions of Dollars		
	2018	2017	2016
Exploratory well costs capitalized for a period of one year or less	**$ 145**	67	132
Exploratory well costs capitalized for a period greater than one year	**711**	786	931
Ending balance	**$ 856**	853	1,063
Number of projects with exploratory well costs capitalized for a period greater than one year	**24**	23	26

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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, 2018:

	Millions of Dollars			
		Suspended Since		
	Total	2015–2017	2012–2014	2004–2011
Greater Poseidon—Australia(2)	177	-	165	12
Barossa/Caldita—Australia(2)	136	59	-	77
Surmont—Canada(1)	108	18	56	34
NPRA—Alaska(1)	77	39	38	-
Middle Magdalena Basin—Colombia(1)	65	65	-	-
Greater Clair—UK(2)	42	8	30	4
Bohai—China(2)	19	19	-	-
Kamunsu East—Malaysia(2)	19	-	19	-
NC 98—Libya(2)	15	-	11	4
Sunrise—Australia(2)	13	-	-	13
Other of $10 million or less each(1)(2)	40	5	18	17
Total	$ 711	213	337	161

(1)Additional appraisal wells planned.
(2)Appraisal drilling complete; costs being incurred to assess development.

In July 2016, we entered into an agreement to terminate our final Gulf of Mexico deepwater drillship contract. The drillship, used to drill our operated deepwater well inventory in the Gulf of Mexico through April 2016, was contracted on a shared, three-year term. Accordingly, we recorded before-tax rig cancellation charges and third-party costs of $146 million in our Lower 48 segment in 2016.

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.

Note 9—Impairments

During 2018, 2017 and 2016, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2018	2017	2016
Alaska	**$ 20**	180	1
Lower 48	**63**	3,969	149
Canada	**9**	22	88
Europe and North Africa	**(79)**	46	(160)
Asia Pacific and Middle East	**14**	2,384	44
Corporate	**-**	-	17
	$ 27	6,601	139

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 United Kingdom 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—Assets Held for Sale, Sold or Acquired and Other Planned 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 United Kingdom 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.

2016
In the Lower 48, we recorded impairments of $149 million primarily due to cancelled projects associated with plan of development changes for Eagle Ford infrastructure, as well as lower natural gas prices and increased ARO estimates.

In Canada, we recorded impairments of $88 million mainly due to plan of development changes, as well as certain developed properties being written down to fair value less costs to sell.

In Europe and North Africa, we recorded a credit to impairment of $160 million, primarily in the United Kingdom, due to decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years, partly offset by asset impairments due to lower natural gas prices in the United Kingdom.

In Asia Pacific and Middle East, we recorded impairments of $44 million, mainly due to a write-down to fair value less costs to sell of our developed properties in Block B, offshore Indonesia, in the third quarter of 2016.

In Corporate and Other, we recorded impairments of $17 million due to cancelled projects in our Houston and Bartlesville offices.

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.

Charges recorded in exploration expenses in 2016 were related to our decision announced in 2015 to reduce deepwater exploration spending.

In our Lower 48 segment, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. Additionally, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect and a $79 million before-tax impairment, primarily as a result of changes in the estimated market value following the completion of marketing efforts.

In our Canada segment, we recorded before-tax unproved property impairments of $31 million, primarily due to decisions to discontinue additional testing of undeveloped leaseholds.

Note 10—Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2018	2017
Asset retirement obligations	**$ 7,908**	7,798
Accrued environmental costs	**178**	180
Total asset retirement obligations and accrued environmental costs	**8,086**	7,978
Asset retirement obligations and accrued environmental costs due within one year*	**(398)**	(347)
Long-term asset retirement obligations and accrued environmental costs	**$ 7,688**	7,631

**Classified as a current liability on the balance sheet under “Other accruals.”*

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.

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During 2018 and 2017, our overall ARO changed as follows:

	Millions of Dollars	
	2018	2017
Balance at January 1	**$ 7,798**	8,405
Accretion of discount	**348**	358
New obligations	**657**	113
Changes in estimates of existing obligations	**(266)**	(150)
Spending on existing obligations	**(228)**	(152)
Property dispositions	**(161)**	(1,065)
Foreign currency translation	**(240)**	289
Balance at December 31	**$ 7,908**	7,798

Accrued Environmental Costs
Total accrued environmental costs at December 31, 2018 and 2017, were $178 million and $180 million, respectively.

We had accrued environmental costs of $100 million and $105 million at December 31, 2018 and 2017, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $67 million and $60 million of environmental costs associated with sites no longer in operation at December 31, 2018 and 2017, respectively. In addition, $11 million and $15 million were included at both December 31, 2018 and 2017, 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 $88 million at December 31, 2018. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $6 million in 2019, $6 million in 2020, $10 million in 2021, $6 million in 2022, $2 million in 2023, and $109 million for all future years after 2023.

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Note 11—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2018	2017
9.125% Debentures due 2021	**$ 123**	150
8.20% Debentures due 2025	**134**	150
8.125% Notes due 2030	**390**	600
7.9% Debentures due 2047	**60**	100
7.8% Debentures due 2027	**203**	300
7.65% Debentures due 2023	**78**	88
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
4.20% Notes due 2021	**-**	1,000
4.15% Notes due 2034	**246**	500
3.35% Notes due 2024	**426**	1,000
3.35% Notes due 2025	**199**	500
2.875% Notes due 2021	**-**	750
2.4% Notes due 2022	**329**	1,000
2.2% Notes due 2020	**-**	500
Floating rate notes due 2018 at 1.24% – 1.75% during 2017	**-**	250
Floating rate notes due 2022 at 2.32% – 3.52% during 2018 and 1.81% – 2.32% during 2017	**500**	500
Industrial Development Bonds due 2018 through 2038 at 0.95% – 1.86% during 2018 and 0.64% – 1.74% during 2017	**18**	18
Marine Terminal Revenue Refunding Bonds due 2031 at 0.88% – 1.95% during 2018 and 0.64% – 1.74% during 2017	**265**	265
Other	**17**	23
Debt at face value	**13,971**	18,677
Capitalized leases	**777**	774
Net unamortized premiums, discounts and debt issuance costs	**220**	252
Total debt	**14,968**	19,703
Short-term debt	**(112)**	(2,575)
Long-term debt	**$ 14,856**	17,128

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Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2019 through 2023 are: $112 million, $101 million, $213 million, $935 million and $195 million, respectively.

In May 2018, we refinanced our revolving credit facility from a total aggregate principal amount of $6.75 billion to $6.0 billion with a new 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 United States. 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, 2018 or December 31, 2017. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at December 31, 2018 or December 31, 2017. 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, 2018.

In 2018, we repaid the $250 million floating rate note due in 2018 at its natural maturity.

We also redeemed or repurchased a total $4,450 million of debt in 2018, described below, incurring $208 million in net premiums above book value, which are reported in the "Other expenses" line on our consolidated income statement.

- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.
- 2.4% Notes due 2022 with principal of $1.0 billion (partial repurchase of $671 million).
- 3.35% Notes due 2024 with principal of $1.0 billion (partial repurchase of $574 million).
- 2.2% Notes due 2020 with principal of $500 million.
- 3.35% Notes due 2025 with principal of $500 million (partial repurchase of $301 million).
- 4.15% Notes due 2034 with principal of $500 million (partial repurchase of $254 million).
- 8.125% Notes due 2030 with principal of $600 million (partial repurchase of $210 million).
- 7.8% Notes due 2027 with principal of $300 million (partial repurchase of $97 million).
- 7.9% Notes due 2047 with principal of $100 million (partial repurchase of $40 million).
- 9.125% Notes due 2021 with principal of $150 million (partial repurchase of $27 million).
- 8.20% Notes due 2025 with principal of $150 million (partial repurchase of $16 million).
- 7.65% Notes due 2023 with principal of $88 million (partial repurchase of $10 million).

At both December 31, 2018 and 2017, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the "Long-term debt" line on our consolidated balance sheet.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our before-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Our proportionate interest in the FPS is 29 percent as of December 31, 2018. The net carrying value of the capital lease asset was approximately $353 million and $434 million as of December 31, 2018 and 2017, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the "Depreciation, depletion and amortization" line on our consolidated income statement. As of December 31, 2018 and 2017, accumulated depreciation of the capital lease asset amounted to approximately $462 million and $381 million, respectively.

At December 31, 2018, future minimum payments due under capital leases 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

Note 12—Guarantees

At December 31, 2018, 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, 2018, 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 2018 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 12 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, 2018, 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 23 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $800 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 27 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $140 million and would become payable if APLNG does not perform.

Other Guarantees
We have other guarantees with maximum future potential payment amounts totaling approximately $780 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 four 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.

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, 2018, was approximately $90 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, 2018, 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.

In 2012, we completed the separation of our downstream business, creating two independent energy companies: ConocoPhillips and Phillips 66. On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream businesses formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. As of December 31, 2017, the carrying value of this guarantee was $98 million. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we also recorded an indemnification asset from Phillips 66 of $98 million. During the third quarter of 2018, a termination agreement between the supplier and Phillips 66 was executed, releasing all parties from their respective obligations under the supply agreement. Since all obligations under the supply agreement were satisfied and discharged, the guarantee was terminated. As of December 31, 2018, the carrying value of this guarantee and the associated indemnification asset have been removed.

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. Environmental Protection Agency (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, 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, 2018, we had performance obligations secured by letters of credit of $323 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 World Bank’s International Centre for Settlement of Investment Disputes (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. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela’s actions.

In 2014, ConocoPhillips filed a separate and independent arbitration under the rules of the International Chamber of Commerce (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. By year-end 2018, we collected from PDVSA under the settlement and recognized in other income $430 million before-tax consisting of $230 million from the sale of commodity inventory and $200 million in cash. The remainder of the initial payments will become an adjustment to a future quarterly installment. Per the settlement, PDVSA recognized the ICC award as a judgment in various jurisdictions, and ConocoPhillips agreed to suspend its legal enforcement actions, including in the Dutch Caribbean. ConocoPhillips has ensured that the settlement meets all appropriate U.S. regulatory requirements, including 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. This ICC arbitration is currently in progress.

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 $24 million contribution from Perenco Ecuador Limited, its co-venturer and consortium operator, pursuant to a joint and several liability provision in the joint operating agreement (JOA). Ecuador's environmental and infrastructure counterclaims against Perenco remain pending in a separate ICSID arbitration between Perenco and Ecuador, and Burlington may owe Perenco contribution under the JOA for damages found by this tribunal.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. In 2018, the parties reached a confidential settlement.

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. This arbitration is ongoing.

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 tribunal was constituted in February 2018. The arbitration is ongoing.

In 2017 and 2018, cities, counties, a state government, and a trade association 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.

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. 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: 2019—$7 million; 2020—$7 million; 2021—$7 million; 2022—$7 million; 2023—$7 million; and 2024 and after—$61 million. Total payments under the agreements were $39 million in 2018, $43 million in 2017 and $42 million in 2016.

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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 natural gas liquids.

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 normal purchase normal sale 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	
	2018	2017
Assets		
Prepaid expenses and other current assets	$ **410**	275
Other assets	**40**	36
Liabilities		
Other accruals	**370**	282
Other liabilities and deferred credits	**30**	28

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

	Millions of Dollars		
	2018	2017	2016
Sales and other operating revenues	$ **45**	77	(198)
Other income	**7**	-	(1)
Purchased commodities	**(41)**	(61)	161

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

	Open Position Long/(Short)	
	2018	2017
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(17)**	(29)
Basis	**(1)**	12

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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	
	2018	2017
Assets		
Prepaid expenses and other current assets	**$ 7**	1
Other assets	**-**	6
Liabilities		
Other accruals	**6**	-
Other liabilities and deferred credits	**-**	15

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

	Millions of Dollars		
	2018	2017	2016
Foreign currency transaction losses	**$ 1**	13	247

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

		In Millions Notional Currency	
		2018	2017
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy British pound	USD	**805**	-
Sell British pound, buy other currencies*	GBP	**21**	1
Sell Canadian dollar, buy U.S. dollar	CAD	**1,242**	1,225

**Primarily euro and Norwegian krone.*

Financial Instruments
We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments that we currently invest include:

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.

- Government or government agency obligations: Short-term securities issued by the U.S. government or U.S. government agencies.

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These financial instruments appear in the "Cash and cash equivalents" line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these financial instruments are included in the "Short-term investments" line on our consolidated balance sheet.

	Millions of Dollars			
	Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments	
	2018	2017	**2018**	2017
Cash	**$ 876**	948		
Time Deposits				
Remaining maturities from 1 to 90 days	**3,509**	5,004	**-**	821
Commercial Paper				
Remaining maturities from 1 to 90 days	**229**	373	**248**	978
Remaining maturities from 91 to 180 days	**-**	-	**-**	74
Government Obligations				
Remaining maturities from 1 to 90 days	**1,301**	-	**-**	-
	$ 5,915	6,325	**248**	1,873

Credit Risk
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (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 and time deposits with major international banks and financial institutions.

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 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, 2018 and December 31, 2017, was $62 million and $55 million, respectively. For these instruments, no collateral was posted as of December 31, 2018 or December 31, 2017. If our credit rating had been downgraded below investment grade on December 31, 2018, we would be required to post $62 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. At the end of the fourth quarter of 2017, our $1,899 million investment in Cenovus Energy was transferred from Level 2 to Level 1 due to the lapsing of trading restrictions. There were no other material transfers in or out of Level 1 during 2018 or 2017.

Recurring Fair Value Measurement
Financial assets and liabilities reported at fair value on a recurring basis primarily include our investment in Cenovus Energy shares 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 New York Stock Exchange. 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 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, 2018				December 31, 2017			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Investment in Cenovus Energy	**$ 1,462**	**-**	**-**	**1,462**	1,899	-	-	1,899
Commodity derivatives	**236**	**181**	**33**	**450**	175	106	30	311
Total assets	**$ 1,698**	**181**	**33**	**1,912**	2,074	106	30	2,210
Liabilities								
Commodity derivatives	**$ 225**	**145**	**30**	**400**	158	111	41	310
Total liabilities	**$ 225**	**145**	**30**	**400**	158	111	41	310

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 offset exists.

	Millions of Dollars					
	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Gross Amounts without Right of Setoff	Net Amounts
December 31, 2018						
Assets	**$ 450**	**280**	**170**	**-**	**9**	**161**
Liabilities	**400**	**280**	**120**	**10**	**4**	**106**
December 31, 2017						
Assets	$ 311	186	125	-	4	121
Liabilities	310	186	124	7	5	112

At December 31, 2018 and December 31, 2017, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

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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 3 Inputs	Before-Tax Loss
Year ended December 31, 2018				
Net PP&E (held for sale)				
March 31, 2018	**$ 250**	**-**	**250**	**44**
September 30, 2018	**201**	**201**	**-**	**43**
Year ended December 31, 2017				
Net PP&E (held for use)				
December 31, 2017	$ 75	-	75	154
Net PP&E (held for sale)				
June 30, 2017	2,830	2,830	-	3,882
December 31, 2017	113	113	-	78
Equity method investments				
June 30, 2017	7,656	-	7,656	2,384

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—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions.

Net PP&E (held for use)
Net PP&E held for use is comprised of various producing properties impaired to their individual fair values. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

Equity Method Investments
During 2017, our investment in APLNG was written down to its fair value of $7,656 million, resulting in a before-tax-charge of $2,384 million. For additional information on APLNG, see Note 6—Investments, Loans and Long-Term Receivables.

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.
- 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.

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- 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	
	2018	2017	**2018**	2017
Financial assets				
Investment in Cenovus Energy	**$ 1,462**	1,899	**1,462**	1,899
Commodity derivatives	**170**	125	**170**	125
Total loans and advances—related parties	**468**	586	**468**	586
Financial liabilities				
Total debt, excluding capital leases	**14,191**	18,929	**16,147**	22,435
Commodity derivatives	**110**	117	**110**	117

Commodity Derivatives
At December 31, 2018, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $10 million of rights to reclaim cash collateral, respectively. At December 31, 2017, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $7 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		
	2018	2017	2016
Issued			
Beginning of year	**1,785,419,175**	1,782,079,107	1,778,226,388
Distributed under benefit plans	**6,218,259**	3,340,068	3,852,719
End of year	**1,791,637,434**	1,785,419,175	1,782,079,107
Held in Treasury			
Beginning of year	**608,312,034**	544,809,771	542,230,673
Repurchase of common stock	**44,976,179**	63,502,263	2,579,098
End of year	**653,288,213**	608,312,034	544,809,771

Preferred Stock
We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2018 or 2017.

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Noncontrolling Interests
At December 31, 2018 and 2017, we had $125 million and $194 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
On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to repurchase an additional $3 billion of common stock through 2019. On July 12, 2018, we announced an authorization of an additional $9 billion for share repurchases bringing the total program authorization to $15 billion. Repurchase of shares began in November 2016, and totaled 111,057,540 shares at a cost of $6.1 billion, through December 31, 2018.

Note 17—Non-Mineral Leases

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 11—Debt.

At December 31, 2018, future minimum rental payments due under noncancelable leases 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

Operating lease rental expense for the years ended December 31 was:

	Millions of Dollars		
	2018	2017	2016
Total rentals	**$ 253**	264	537
Less: sublease rentals	**(16)**	(20)	(10)
	$ 237	244	527

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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	
	2018		2017		**2018**	2017
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 3,236**	**3,845**	3,416	3,445	**265**	286
Service cost	**83**	**81**	89	77	**1**	2
Interest cost	**99**	**107**	118	103	**8**	9
Plan participant contributions	**-**	**2**	-	2	**22**	23
Plan amendments	**-**	**7**	-	-	**-**	-
Actuarial (gain) loss	**(44)**	**(259)**	244	52	**(10)**	12
Benefits paid	**(507)**	**(143)**	(631)	(117)	**(67)**	(68)
Curtailment	**(4)**	**(3)**	-	-	**-**	-
Settlement	**(730)**	**-**	-	-	**-**	-
Recognition of termination benefits	**3**	**-**	-	-	**-**	-
Foreign currency exchange rate change	**-**	**(199)**	-	283	**(1)**	1
Benefit obligation at December 31*	**$ 2,136**	**3,438**	3,236	3,845	**218**	265
**Accumulated benefit obligation portion of above at December 31:*	***$ 1,969***	***3,066***	*3,076*	*3,404*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 2,541**	**3,647**	2,081	3,068	**-**	-
Actual return on plan assets	**(112)**	**(106)**	336	313	**-**	-
Company contributions	**144**	**156**	755	114	**45**	45
Plan participant contributions	**-**	**2**	-	2	**22**	23
Benefits paid	**(507)**	**(143)**	(631)	(117)	**(67)**	(68)
Settlement	**(730)**	**-**	-	-	**-**	-
Foreign currency exchange rate change	**-**	**(198)**	-	267	**-**	-
Fair value of plan assets at December 31	**$ 1,336**	**3,358**	2,541	3,647	**-**	-
Funded Status	**$ (800)**	**(80)**	(695)	(198)	**(218)**	(265)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2018		2017		**2018**	2017
	U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	**$ -**	**232**	-	205	**-**	-
Current liabilities	**(59)**	**(4)**	(38)	(4)	**(44)**	(45)
Noncurrent liabilities	**(741)**	**(308)**	(657)	(399)	**(174)**	(220)
Total recognized	**$ (800)**	**(80)**	(695)	(198)	**(218)**	(265)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**4.25%**	**3.05**	3.55	2.80	**4.05**	3.30
Rate of compensation increase	**4.00**	**3.65**	4.00	3.75	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**3.80%**	**2.90**	3.80	3.00	**3.30**	3.60
Expected return on plan assets	**5.80**	**4.30**	6.55	5.05	**-**	-
Rate of compensation increase	**4.00**	**3.75**	4.00	3.85	**-**	-

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:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2018		2017		**2018**	2017
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial (gain) loss	**$ 516**	**310**	588	358	**(21)**	(12)
Unrecognized prior service cost (credit)	**-**	**(4)**	-	(16)	**(216)**	(249)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2018		2017		**2018**	2017
	U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)						
Net gain (loss) arising during the period	**$ (177)**	**17**	(40)	71	**10**	(12)
Amortization of (gain) loss included in income (loss)*	**249**	**31**	200	50	**(1)**	(3)
Net change during the period	**$ 72**	**48**	160	121	**9**	(15)
Prior service credit (cost) arising during the period	**$ -**	**(7)**	-	2	**-**	-
Amortization of prior service cost (credit) included in income (loss)	**-**	**(5)**	4	(6)	**(35)**	(36)
Net change during the period	**$ -**	**(12)**	4	(4)	**(35)**	(36)

**Includes settlement losses recognized in 2018 and 2017.*

Included in accumulated other comprehensive loss at December 31, 2018, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2019:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int'l.	
Unrecognized net actuarial (gain) loss	$ 52	31	(2)
Unrecognized prior service credit	-	(2)	(33)

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 $4,110 million, $3,768 million, and $3,702 million, respectively, at December 31, 2018, and $5,634 million, $5,226 million, and $5,113 million, respectively, at December 31, 2017.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $586 million and $504 million, respectively, at December 31, 2018, and were $578 million and $503 million, respectively, at December 31, 2017.

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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		
	2018		2017		2016		**2018**	2017	2016
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 83**	**81**	89	77	108	76	**1**	2	2
Interest cost	**99**	**107**	118	103	133	120	**8**	9	13
Expected return on plan assets	**(114)**	**(155)**	(132)	(158)	(149)	(147)	**-**	-	-
Amortization of prior service cost (credit)	**-**	**(5)**	4	(6)	5	(6)	**(35)**	(36)	(34)
Recognized net actuarial loss (gain)	**53**	**31**	69	50	86	26	**(1)**	(3)	(2)
Settlements	**196**	**-**	131	-	202	-	**-**	-	-
Curtailment loss	**-**	**-**	-	-	14	-	**-**	-	1
Net periodic benefit cost	**$ 317**	**59**	279	66	399	69	**(27)**	(28)	(20)

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 $196 million in 2018, $131 million in 2017, and $202 million in 2016 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.

As part of the 2016 restructuring program, we concluded that actions taken during the year resulted in a significant reduction of future services of active employees primarily in the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as a curtailment loss of $15 million during the year ended December 31, 2016.

Also, as part of the 2016 restructuring program in the United States and Europe, we recognized expense for special termination benefits of $15 million during the year ended December 31, 2016, consisting of $14 million in the United States and $1 million in Europe.

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 2019 that declines to 5 percent by 2024. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes an ultimate health care cost trend rate of 5 percent achieved in 2019. 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 39 percent equity securities, 54 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, 2018 and 2017.

- 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, 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

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benefit obligation covered by the contract. At December 31, 2017, the participating interest in the annuity contract was valued at $99 million and consisted of $265 million in debt securities, less $166 million for the accumulated benefit obligation covered by the contract. The net change from 2017 to 2018 is due to a decrease in the fair value of the underlying investments of $37 million offset by a decrease in the present value of the contract obligation of $22 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
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								
Corporate	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Agency and mortgage-backed 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 value of $84 million and net receivables related to security transactions of $16 million.*

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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
2017								
Equity securities								
U.S.	$ 161	-	14	175	440	-	-	440
International	178	-	-	178	315	-	-	315
Mutual funds	146	-	-	146	292	165	-	457
Debt securities								
Government	-	-	-	-	902	-	-	902
Corporate	-	2	-	2	-	-	-	-
Mutual funds	-	-	-	-	144	-	-	144
Cash and cash equivalents	-	-	-	-	111	-	-	111
Time deposits	-	-	-	-	3	-	-	3
Derivatives	-	-	-	-	5	-	-	5
Real estate	-	-	-	-	-	-	123	123
Total in fair value hierarchy	$ 485	2	14	501	2,212	165	123	2,500
Investments measured at net asset value*								
Equity securities								
Common/collective trusts	$ -	-	-	805	-	-	-	183
Debt securities								
Corporate	-	-	-	-	-	-	-	172
Agency and mortgage-backed securities	-	-	-	-	-	-	-	15
Common/collective trusts	-	-	-	1,042	-	-	-	648
Cash and cash equivalents	-	-	-	17	-	-	-	24
Real estate	-	-	-	74	-	-	-	94
Total**	$ 485	2	14	2,439	2,212	165	123	3,636

**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 value of $99 million and net payables related to security transactions of $14 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 2019, we expect to contribute approximately $195 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $185 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.	
2019	$ 400	123	36
2020	251	129	34
2021	232	137	30
2022	222	138	27
2023	216	143	24
2024–2027	880	788	69

Severance Accrual
As a result of staff reductions occurring throughout the year, severance accruals of $70 million were recorded in 2018. The following table summarizes our severance accrual activity for the year ended December 31, 2018:

	Millions of Dollars
Balance at December 31, 2017	$ 53
Accruals	**70**
Benefit payments	**(73)**
Foreign currency translation adjustments	**(2)**
Balance at December 31, 2018	**$ 48**

Of the remaining balance at December 31, 2018, $23 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 34 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 will be 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 2018, $77 million in 2017, and $58 million in 2016.

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 $31 million in 2018, $35 million in 2017, and $44 million in 2016.

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		
	2018	2017	2016
Compensation cost	**$ 265**	227	272
Tax benefit	**64**	76	92

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 and 2016 were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

	2017	2016
Assumptions used		
Risk-free interest rate	2.24 %	1.55
Dividend yield	4.00 %	4.00
Volatility factor	28.12 %	26.80
Expected life (years)	6.39	6.37

There were no ranges in the assumptions used to determine the fair market values of our options granted in 2017 and 2016.

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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 and 2016, 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, 2018:

	Options	Weighted-Average Exercise Price	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2017	24,722,803	$ 52.18	$ 177
Exercised	**(3,903,130)**	**45.71**	**94**
Forfeited	**(84,694)**	**58.23**	
Expired or cancelled	**(1,355,302)**	**60.53**	
Outstanding at December 31, 2018	**19,379,677**	**$ 52.88**	**$ 214**
Vested at December 31, 2018	**18,820,388**	**$ 53.16**	**$ 204**
Exercisable at December 31, 2018	**16,213,002**	**$ 54.89**	**$ 152**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2018, was 5.16 years, 5.09 years and 4.69 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2017 and 2016 was $9.18 and $5.39, respectively. The aggregate intrinsic value of options exercised was $4 million in 2017 and zero in 2016.

During 2018, we received $178 million in cash and realized a tax benefit of $18 million from the exercise of options. At December 31, 2018, the remaining unrecognized compensation expense from unvested options was $2 million, which will be recognized over a weighted-average period of 0.87 years, the longest period being 1.12 years.

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.

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The following summarizes our stock-settled stock unit activity for the year ended December 31, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	7,826,852	$ 45.75	
Granted	**2,465,100**	**52.45**	
Forfeited	**(173,265)**	**45.72**	
Issued	**(2,571,714)**		**$ 154**
Outstanding at December 31, 2018	**7,546,973**	**$ 43.41**	
Not Vested at December 31, 2018	**5,090,209**	**43.69**	

At December 31, 2018, the remaining unrecognized compensation cost from the unvested stock-settled units was $88 million, which will be recognized over a weighted-average period of 1.68 years, the longest period being 2.76 years. The weighted-average grant date fair value of stock unit awards granted during 2017 and 2016 was $48.77 and $32.15, respectively. The total fair value of stock units issued during 2017 and 2016 was $159 million and $191 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, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	-	$ -	
Granted	**393,571**	**53.68**	
Forfeited	**(3,849)**	**59.17**	
Issued	**(13,114)**		**$ 1**
Outstanding at December 31, 2018	**376,608**	**$ 62.21**	
Not Vested at December 31, 2018	**90,254**	**62.21**	

At December 31, 2018, the remaining unrecognized compensation cost from the unvested cash-settled units was $3 million, which will be recognized over a weighted-average period of 1.79 years, the longest period being 2.12 years.

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, 2018:

		Weighted-Average	Millions of Dollars
	Stock Units	Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2017	2,753,465	$ 50.79	
Granted	**19,708**	**53.28**	
Forfeited	**(2,859)**	**48.89**	
Issued	**(434,772)**		**$ 29**
Outstanding at December 31, 2018	**2,335,542**	**$ 50.45**	
Not Vested at December 31, 2018	**58,914**	**$ 48.41**	

At December 31, 2018, 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 2017 and 2016 was $49.76 and $33.13, respectively. The total fair value of stock-settled PSUs issued during 2017 and 2016 was $57 million and $17 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, 2018:

		Weighted-Average	Millions of Dollars
	Stock Units	Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2017	1,214,533	$55.19	
Granted	**321,965**	**53.28**	
Forfeited	**(9,282)**	**59.17**	
Settled	**(396,209)**		**$22**
Outstanding at December 31, 2018	**1,131,007**	**$62.21**	
Not Vested at December 31, 2018	**87,900**	**$62.21**	

At December 31, 2018, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $1 million, which will be recognized over a weighted-average period of 0.89 years, the longest period being 1.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2017 and 2016 was $49.76 and $33.13, respectively. The total fair value of cash-settled performance share awards settled during 2017 and 2016 was $24 million and $31 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.

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The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	1,301,040	$ 45.77	
Granted	**70,922**	**62.01**	
Cancelled	**(1,334)**	**23.09**	
Issued	**(263,313)**		**$ 17**
Outstanding at December 31, 2018	**1,107,315**	**$ 46.57**	
Not Vested at December 31, 2018	**-**		

At December 31, 2018, 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 2017 and 2016 was $48.87 and $40.36, respectively. The total fair value of awards issued during 2017 and 2016 was $4 million and $2 million, respectively.

Note 19—Income Taxes

Income taxes charged to net income (loss) were:

	Millions of Dollars		
	2018	2017	2016
Income Taxes			
Federal			
Current	**$ 4**	79	(9)
Deferred	**545**	(3,046)	(1,634)
Foreign			
Current	**3,273**	1,729	393
Deferred	**(166)**	(510)	(519)
State and local			
Current	**108**	51	(135)
Deferred	**(96)**	(125)	(67)
	$ 3,668	(1,822)	(1,971)

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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	
	2018	2017
Deferred Tax Liabilities		
PP&E and intangibles	$ **8,004**	9,692
Inventory	**60**	61
Deferred state income tax	**61**	178
Other	**156**	464
Total deferred tax liabilities	**8,281**	10,395
Deferred Tax Assets		
Benefit plan accruals	**641**	786
Asset retirement obligations and accrued environmental costs	**2,891**	3,060
Investments in joint ventures	**104**	57
Other financial accruals and deferrals	**330**	166
Loss and credit carryforwards	**2,378**	2,310
Other	**398**	152
Total deferred tax assets	**6,742**	6,531
Less: valuation allowance	**(3,040)**	(1,254)
Net deferred tax assets	**3,702**	5,277
Net deferred tax liabilities	$ **4,579**	5,118

At December 31, 2018, noncurrent assets and liabilities included deferred taxes of $442 million and $5,021 million, respectively. At December 31, 2017, noncurrent assets and liabilities included deferred taxes of $164 million and $5,282 million, respectively.

At December 31, 2018, 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	$ 1,016	17	2027
U.S. general business credits	364	364	2036-2038
State net operating losses and tax credits	312	32	Various
Foreign net operating losses and tax credits	686	647	Post 2025
	$ 2,378	1,060	

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2018, valuation allowances increased a total of $1,786 million. The increase primarily relates to deferred tax assets recognized during 2018 as a result of the U.S. Tax Cuts and Jobs Act (Tax Legislation), as further discussed below, and are related to U.S. tax basis and foreign tax credits associated with our foreign branch assets that we do not expect to realize. 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.

At December 31, 2018, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,808 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 $190 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2018, 2017 and 2016:

	Millions of Dollars		
	2018	2017	2016
Balance at January 1	**$ 882**	381	459
Additions based on tax positions related to the current year	**268**	612	32
Additions for tax positions of prior years	**43**	109	19
Reductions for tax positions of prior years	**(73)**	(129)	(118)
Settlements	**(35)**	(5)	(9)
Lapse of statute	**(4)**	(86)	(2)
Balance at December 31	**$ 1,081**	882	381

Included in the balance of unrecognized tax benefits for 2018, 2017 and 2016 were $1,081 million, $882 million and $359 million, respectively, which, if recognized, would impact our effective tax rate. The balance of the unrecognized tax benefits increased in 2018 mainly due to the treatment of distributions from certain of 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.

At December 31, 2018, 2017 and 2016, accrued liabilities for interest and penalties totaled $45 million, $54 million and $54 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings of $4 million in 2018, no impact to earnings in 2017, and a benefit to earnings of $18 million in 2016.

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: United Kingdom (2015), Canada (2010), United States (2014) and Norway (2017). 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.

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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)		
		2018	2017	2016	**2018**	2017	2016
Income (loss) before income taxes							
United States	$	**2,867**	(5,250)	(4,410)	**28.7 %**	200.8	79.7
Foreign		**7,106**	2,635	(1,120)	**71.3**	(100.8)	20.3
	$	**9,973**	(2,615)	(5,530)	**100.0 %**	100.0	100.0
Federal statutory income tax	$	**2,095**	(915)	(1,936)	**21.0 %**	35.0	35.0
Non-U.S. effective tax rates		**1,766**	625	361	**17.7**	(23.9)	(6.5)
Tax Legislation		**(10)**	(852)	-	**(0.1)**	32.6	-
Canada disposition		**-**	(1,277)	-	**-**	48.8	-
U.K. disposition		**(150)**	-	-	**(1.5)**	-	-
Recovery of outside basis		**(21)**	(962)	(60)	**(0.2)**	36.8	1.1
Adjustment to tax reserves		**(4)**	881	55	**-**	(33.7)	(1.0)
Adjustment to valuation allowance		**(26)**	-	-	**(0.3)**	-	-
APLNG impairment		**-**	834	-	**-**	(31.9)	-
State income tax		**135**	(84)	(122)	**1.4**	3.2	2.2
Enhanced oil recovery credit		**(99)**	(68)	(62)	**(1.0)**	2.6	1.1
U.K. rate change		**-**	-	(161)	**-**	-	2.9
Other		**(18)**	(4)	(46)	**(0.2)**	0.2	0.8
	$	**3,668**	(1,822)	(1,971)	**36.8 %**	69.7	35.6

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 ConocoPhillips subsidiary to BP. The subsidiary held a 16.5 percent interest in the BP-operated Clair Field in the United Kingdom. The disposition generated a before-tax gain of $715 million with no associated tax cost. See Note 5—Assets Held for Sale, Sold or Acquired and Other Planned Dispositions for additional information on the U.K. disposition.

Tax Legislation was enacted in the United States 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 have now 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. At December 31, 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—Assets Held for Sale, Sold or Acquired and Other Planned 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.

The decrease in the effective tax rate for 2016 was primarily due to our mix of income among taxing jurisdictions, reduced net tax benefit from the tax law changes discussed below, and the absence of a tax benefit associated with electing the fair market value method of apportioning interest expense for prior years.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, we recorded a $161 million net tax benefit related to the remeasurement of our U.K. deferred tax balance in 2016.

Certain operating losses in jurisdictions outside of the United States only yield a tax benefit in the United States as a worthless security deduction. For 2018, 2017 and 2016, before consideration of unrecorded tax benefits discussed above, the amount of the tax benefit was $36 million, $962 million and $60 million, respectively.

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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, 2015	$	(443)	-	(5,804)	(6,247)
Other comprehensive income (loss)		(104)	-	158	54
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)**

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

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		
	2018		2017
Defined Benefit Plans	**$**	**189**	135
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	***$***	***50***	*74*

See Note 18—Employee Benefit Plans, for additional information.

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Note 21—Cash Flow Information

	Millions of Dollars		
	2018	2017	2016
Noncash Investing Activities			
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	**$ 395**	(37)	(1,017)
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 (Receipts)			
Interest	**$ 772**	1,163	1,151
Income taxes	**2,976**	1,168	(318)**
Net Sales (Purchases) of Short-Term Investments			
Short-term investments purchased	**$ (1,953)**	(6,617)	(1,753)
Short-term investments sold	**3,573**	4,827	1,702
	$ 1,620	(1,790)	(51)

**See Note 5—Assets Held for Sale, Sold, or Acquired and Other Planned Dispositions.*
***2016 is net of $585 million related to refunds received from the Internal Revenue Service.*

The following items are included in in the “Cash Flows from Operating Activities” section of our consolidated cash flows.

In 2018, we collected $430 million from PDVSA consisting of $230 million from the sale of commodity inventory and $200 million in cash, as partial payments 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.

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.

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Note 22—Other Financial Information

		Millions of Dollars		
		2018	2017	2016
Interest and Debt Expense				
Incurred				
Debt	$	**838**	1,114	1,279
Other		**67**	103	123
		905	1,217	1,402
Capitalized		**(170)**	(119)	(157)
Expensed	$	**735**	1,098	1,245
Other Income				
Interest income	$	**97**	112	57
Other, net		**76**	417	198
	$	**173**	529	255
Research and Development Expenditures—expensed	$	**78**	100	116
Shipping and Handling Costs*	$	**1,075**	1,050	1,140

**Amounts included in production and operating expenses. 2017 and 2016 have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07. See Note 2—Changes in Accounting Principles, for additional information.*

Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**-**	-	-
Lower 48		**-**	-	-
Canada		**(11)**	3	1
Europe and North Africa		**(26)**	7	(7)
Asia Pacific and Middle East		**3**	23	(9)
Other International		**-**	1	7
Corporate and Other		**21**	(3)	(18)
	$	**(13)**	31	(26)

	Millions of Dollars	
	2018	2017
Properties, Plants and Equipment		
Proved properties	**$ 100,657**	102,044
Unproved properties	**4,662**	4,491
Other	**5,278**	3,896
Gross properties, plants and equipment	**110,597**	110,431
Less: Accumulated depreciation, depletion and amortization	**(64,899)**	(64,748)
Net properties, plants and equipment	**$ 45,698**	45,683

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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		
	2018	2017	2016
Operating revenues and other income	$ **98**	107	133
Purchases	**98**	99	101
Operating expenses and selling, general and administrative expenses	**60**	59	63
Net interest (income) expense*	**(14)**	(13)	(12)

**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

Transitional Arrangements

We adopted the provisions of ASC Topic 606 beginning January 1, 2018, using the modified retrospective approach, which we have applied to contracts within the scope of the standard that had not been completed as of January 1, 2018. Results for reporting periods beginning after January 1, 2018, are presented under ASC Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with ASC Topic 605. See Note 2—Changes in Accounting Principles for the effect on our consolidated balance sheet and the line items which have been impacted by the adoption of this standard.

The cumulative effect of applying the standard relates solely to certain licensing arrangements where revenue was previously recognized ($61 million in 2011, $146 million in 2015, and $44 million in 2017) based on contractual milestones. Under ASC Topic 606, such revenues are recognized when the customer has the ability to utilize and benefit from its right to use the license. As a result, such historically recognized revenues must be reversed through a cumulative effect adjustment and deferred until such time when the customer has the ability to utilize and benefit from the license. The cumulative effect adjustment relates to contracts that were not substantially completed at the date of implementation.

Practical Expedients

Typically, our commodity sales contracts are less than 12 months in duration; however, certain commodity sales contracts may carry a longer duration, which may extend 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.

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Revenue from Contracts with Customers

The following table provides further disaggregation of our consolidated sales and other operating revenues:

		Millions of Dollars		
		2018	2017 *	2016 *
Revenue from contracts with customers	$	**28,098**	20,525	16,527
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative		**8,218**	8,669	7,278
Financial derivative contracts		**101**	(88)	(112)
Consolidated sales and other operating revenues	$	**36,417**	29,106	23,693

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

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 normal purchases and normal sales (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		
		2018	2017 *	2016 *
Revenue from Outside the Scope of ASC Topic 606 by Segment				
Lower 48	$	**6,358**	6,302	5,391
Canada		**629**	864	813
Europe and North Africa		**1,231**	1,503	1,074
Physical contracts meeting the definition of a derivative	$	**8,218**	8,669	7,278

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

		Millions of Dollars		
		2018	2017 *	2016 *
Revenue from Outside the Scope of ASC Topic 606 by Product				
Crude oil	$	**1,112**	588	436
Natural gas		**6,734**	7,811	6,502
Other		**372**	270	340
Physical contracts meeting the definition of a derivative	$	**8,218**	8,669	7,278

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

Receivables and Contract Liabilities

Receivables from Contracts with Customers

At December 31, 2018, the "Accounts and notes receivable" line on our consolidated balance sheet included trade receivables of $2,889 million compared with $2,675 million at December 31, 2017, 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 January 1, 2018	**$**	**251**
Contractual payments received		**103**
Revenue recognized		**(148)**
At December 31, 2018	**$**	**206**
Amounts Recognized in the Consolidated Balance Sheet at December 31, 2018		
Current liabilities	**$**	**169**
Noncurrent liabilities		**37**
	$	**206**

During 2018, we recognized revenue of $148 million in the "Sales and other operating revenues" line on our consolidated income statement. We expect to recognize the contract liabilities as of December 31, 2018, as revenue between the remainder of 2019 and 2022 as construction is completed.

Prior to the adoption of ASC Topic 606, contractual cash payments received were recognized as "Sales and other operating revenues" when received.

Note 25—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids 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.

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Analysis of Results by Operating Segment

	Millions of Dollars		
	2018	2017	2016
Sales and Other Operating Revenues			
Alaska	**$ 5,740**	4,224	3,681
Lower 48	**17,029**	12,968	10,719
Intersegment eliminations	**(40)**	(4)	(17)
Lower 48	**16,989**	12,964	10,702
Canada	**3,184**	3,178	2,192
Intersegment eliminations	**(1,160)**	(559)	(218)
Canada	**2,024**	2,619	1,974
Europe and North Africa	**6,635**	5,181	3,462
Asia Pacific and Middle East	**4,861**	4,014	3,705
Corporate and Other	**168**	104	169
Consolidated sales and other operating revenues	**$ 36,417**	29,106	23,693
Depreciation, Depletion, Amortization and Impairments			
Alaska	**$ 760**	1,026	868
Lower 48	**2,370**	6,693	4,358
Canada	**324**	461	975
Europe and North Africa	**1,041**	1,313	1,253
Asia Pacific and Middle East	**1,382**	3,819	1,606
Other International	**-**	-	1
Corporate and Other	**106**	134	140
Consolidated depreciation, depletion, amortization and impairments	**$ 5,983**	13,446	9,201

In 2018, sales by our Lower 48, Alaska and Canada segments to a certain refining company accounted for approximately $4 billion or 11 percent of our total consolidated sales and other operating revenues.

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	Millions of Dollars		
	2018	2017	2016
Equity in Earnings of Affiliates			
Alaska	**$ 6**	7	9
Lower 48	**1**	5	(6)
Canada	**-**	197	89
Europe and North Africa	**16**	10	22
Asia Pacific and Middle East	**1,051**	553	(51)
Other International	**-**	-	-
Corporate and Other	**-**	-	(11)
Consolidated equity in earnings of affiliates	**$ 1,074**	772	52
Income Taxes			
Alaska	**$ 376**	(689)	(59)
Lower 48	**474**	(2,453)	(1,328)
Canada	**(96)**	(616)	(383)
Europe and North Africa	**2,265**	1,165	(46)
Asia Pacific and Middle East	**722**	351	306
Other International	**30**	21	(40)
Corporate and Other	**(103)**	399	(421)
Consolidated income taxes	**$ 3,668**	(1,822)	(1,971)
Net Income (Loss) Attributable to ConocoPhillips			
Alaska	**$ 1,814**	1,466	319
Lower 48	**1,747**	(2,371)	(2,257)
Canada	**63**	2,564	(935)
Europe and North Africa	**1,866**	553	394
Asia Pacific and Middle East	**2,070**	(1,098)	209
Other International	**364**	167	(16)
Corporate and Other	**(1,667)**	(2,136)	(1,329)
Consolidated net income (loss) attributable to ConocoPhillips	**$ 6,257**	(855)	(3,615)
Investments in and Advances to Affiliates			
Alaska	**$ 86**	56	58
Lower 48	**378**	402	426
Canada	**-**	-	8,784
Europe and North Africa	**55**	55	62
Asia Pacific and Middle East	**8,821**	9,077	11,611
Other International	**-**	-	-
Corporate and Other	**-**	-	4
Consolidated investments in and advances to affiliates	**$ 9,340**	9,590	20,945

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	Millions of Dollars		
	2018	2017	2016
Total Assets			
Alaska	**$ 14,648**	12,108	12,314
Lower 48	**14,888**	14,632	22,673
Canada	**5,748**	6,214	17,548
Europe and North Africa	**9,883**	11,870	11,727
Asia Pacific and Middle East	**16,151**	16,985	20,451
Other International	**89**	97	97
Corporate and Other	**8,573**	11,456	4,962
Consolidated total assets	**$ 69,980**	73,362	89,772
Capital Expenditures and Investments			
Alaska	**$ 1,298**	815	883
Lower 48	**3,184**	2,136	1,262
Canada	**477**	202	698
Europe and North Africa	**877**	872	1,020
Asia Pacific and Middle East	**718**	482	838
Other International	**6**	21	104
Corporate and Other	**190**	63	64
Consolidated capital expenditures and investments	**$ 6,750**	4,591	4,869
Interest Income and Expense			
Interest income			
Corporate	**$ 80**	101	47
Lower 48	**-**	-	-
Europe and North Africa	**2**	2	2
Asia Pacific and Middle East	**15**	9	8
Other International	**-**	-	-
Interest and debt expense Corporate	**$ 735**	1,098	1,245
Sales and Other Operating Revenues by Product			
Crude oil	**$ 19,571**	13,260	10,801
Natural gas	**10,720**	10,773	9,401
Natural gas liquids	**1,114**	1,102	837
Other*	**5,012**	3,971	2,654
Consolidated sales and other operating revenues by product	**$ 36,417**	29,106	23,693

**Includes LNG and bitumen.*

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Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues(1)			Long-Lived Assets(2)		
	2018	2017	2016	**2018**	2017	2016
United States	**$ 22,740**	17,204	14,400	**26,838**	23,623	32,949
Australia(3)	**1,798**	1,448	1,353	**9,301**	9,657	12,259
Canada	**2,024**	2,619	1,974	**5,333**	5,613	16,846
China	**836**	712	551	**1,380**	1,275	1,372
Indonesia	**886**	757	938	**669**	758	856
Libya(4)	**1,142**	586	-	**679**	699	704
Malaysia	**1,346**	1,103	735	**2,327**	2,736	3,323
Norway	**2,886**	2,348	1,645	**5,582**	6,154	6,228
United Kingdom	**2,606**	2,248	1,816	**1,583**	3,335	3,209
Other foreign countries	**153**	81	281	**1,346**	1,423	1,530
Worldwide consolidated	**$ 36,417**	29,106	23,693	**55,038**	55,273	79,276

(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 investments in and advances to affiliated companies.
(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.
(4)Included in "Other foreign countries" in prior periods.

Note 26—New Accounting Standards

In February 2016, the FASB issued ASU No. 2016-02, "Leases" (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, "Leases" (FASB ASC Topic 840), and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements.

ASU No. 2016-02 was amended in January 2018 by the provisions of ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842" (ASU No. 2018-01), and in July 2018 by the provisions of ASU No. 2018-10, "Codification Improvements to Topic 842, Leases" (ASU No. 2018-10). In addition, ASU No. 2016-02 was further amended in July 2018 by the provisions of ASU No. 2018-11, "Targeted Improvements" (ASU No. 2018-11), and in December 2018 by the provisions of ASU No. 2018-20, "Narrow-Scope Improvements for Lessors" (ASU No. 2018-20).

ASU No. 2018-11 sets forth certain additional practical expedients for lessors and provides entities with an option to apply the provisions of ASU No. 2016-02, as amended, to leasing arrangements existing at or entered into after the ASU's effective date of adoption (the "Optional Transition Method"). Entities that elect to utilize the Optional Transition Method would not apply the provisions of ASU No. 2016-02, as amended, to comparative periods presented in the financial statements.

We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, utilizing the Optional Transition Method. Accordingly, the comparative periods presented in the financial statements prior to January 1, 2019, will be presented pursuant to the existing requirements of FASB ASC Topic 840 and not be adjusted upon the adoption of the ASU. We also expect to utilize the package of optional transition-related practical expedients set forth by ASU No. 2016-02, as amended, which permit entities to not reassess upon the adoption of the ASU certain historical conclusions regarding lease contract identification and classification, as well as the historical accounting treatment of initial direct costs (the "Package of Optional Practical Expedients"). For lease arrangements containing both lease and non-lease components, we will adopt the optional practical expedient to not separate lease components from non-lease components for all new or modified leases executed on or after the effective date of the ASU, subject to making any elections for leases after the effective date in new asset classes. Furthermore, we do not expect to record assets and liabilities on our consolidated balance sheet for new or existing lease arrangements with terms of 12 months or less.

The expected impact of the adoption of ASU No. 2016-02, as amended, relates primarily to our balance sheet, resulting from the initial recognition of lease liabilities and corresponding right-of-use assets for our existing population of operating leases, as well as enhanced disclosure of our leasing arrangements. We expect to recognize on our consolidated balance sheet approximately $1 billion of operating lease liabilities and corresponding right-of-use assets upon the adoption of ASU No. 2016-02, as amended. We have implemented a third-party lease accounting software solution to facilitate the ongoing accounting and financial reporting requirements of the ASU and also expect the adoption of the ASU to result in certain changes being made to our existing accounting policies and systems, business processes, and internal controls.

While our evaluation of ASU No. 2016-02, as amended, and related implementation activities approach completion, we continue to monitor proposals issued by the FASB to clarify the ASU.

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, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, “Extractive Activities—Oil and Gas,” and regulations of the U.S. Securities and Exchange Commission (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.

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 production sharing contracts (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, 2018, approximately 6 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 5 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, and Africa.

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.

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 2018, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2018, 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, 2018, 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 United States 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.

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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 2015	915	588	1,503	14	346	203	204	2,270
Revisions	(57)	(93)	(150)	3	-	6	-	(141)
Improved recovery	6	3	9	-	-	7	-	16
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	33	79	112	-	-	7	-	119
Production	(60)	(71)	(131)	(3)	(43)	(35)	(1)	(213)
Sales	-	-	-	(1)	-	(3)	-	(4)
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
Equity affiliates								
End of 2015	-	-	-	-	-	93	-	93
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
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
Total company								
End of 2015	915	588	1,503	14	346	296	204	2,363

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

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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 2015	819	283	1,102	13	200	139	204	1,658
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
Equity affiliates								
End of 2015	-	-	-	-	-	93	-	93
End of 2016	-	-	-	-	-	88	-	88
End of 2017	-	-	-	-	-	83	-	83
End of 2018	-	-	-	-	-	78	-	78
Undeveloped								
Consolidated operations								
End of 2015	96	305	401	1	146	64	-	612
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
Equity affiliates								
End of 2015	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2018, included:

- *Revisions*: 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. In 2016, revisions in Lower 48 and Alaska were primarily due to lower prices.

- *Purchases:* In 2018, Alaska purchases were due to the Kuparuk Assets and Western North Slope acquisitions.

- *Extensions and discoveries*: 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. In 2016, extensions and discoveries in Alaska were primarily due to drilling success in the Western North Slope, and extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

- *Sales*: In 2018, Europe sales were due to the disposition of a subsidiary that held a 16.5 percent interest in the Clair Field in the United Kingdom. In 2017, Canada sales were due to the disposition of a majority of our western Canada assets.

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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 2015	114	321	435	45	20	8	508
Revisions	(3)	(29)	(32)	9	2	-	(21)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	18	18	2	-	-	20
Production	(4)	(32)	(36)	(8)	(3)	(3)	(50)
Sales	-	-	-	-	-	-	-
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
Equity affiliates							
End of 2015	-	-	-	-	-	50	50
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
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
Total company							
End of 2015	114	321	435	45	20	58	558
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

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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 2015	114	235	349	45	16	8	418
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
Equity affiliates							
End of 2015	-	-	-	-	-	50	50
End of 2016	-	-	-	-	-	47	47
End of 2017	-	-	-	-	-	45	45
End of 2018	-	-	-	-	-	42	42
Undeveloped							
Consolidated operations							
End of 2015	-	86	86	-	4	-	90
End of 2016	-	69	69	1	4	-	74
End of 2017	-	123	123	-	2	3	128
End of 2018	-	125	125	1	2	-	128
Equity affiliates							
End of 2015	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-	-

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2018, included:

- *Revisions*: 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 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specfic 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 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.

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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 2015	2,347	5,171	7,518	1,107	1,359	1,713	227	11,924
Revisions	(105)	(124)	(229)	111	56	18	-	(44)
Improved recovery	-	-	-	-	-	1	-	1
Purchases	-	-	-	1	-	-	-	1
Extensions and discoveries	2	162	164	43	-	124	-	331
Production	(73)	(494)	(567)	(192)	(177)	(288)	-	(1,224)
Sales	(69)	(1)	(70)	(33)	-	(42)	-	(145)
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
Equity affiliates								
End of 2015	-	-	-	-	-	5,269	-	5,269
Revisions	-	-	-	-	-	(676)	-	(676)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	125	-	125
Production	-	-	-	-	-	(337)	-	(337)
Sales	-	-	-	-	-	-	-	-
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
Total company								
End of 2015	2,347	5,171	7,518	1,107	1,359	6,982	227	17,193
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

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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 2015	2,313	4,458	6,771	1,101	1,088	1,421	227	10,608
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
Equity affiliates								
End of 2015	-	-	-	-	-	4,482	-	4,482
End of 2016	-	-	-	-	-	4,110	-	4,110
End of 2017	-	-	-	-	-	4,044	-	4,044
End of 2018	-	-	-	-	-	4,059	-	4,059
Undeveloped								
Consolidated operations								
End of 2015	34	713	747	6	271	292	-	1,316
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
Equity affiliates								
End of 2015	-	-	-	-	-	787	-	787
End of 2016	-	-	-	-	-	271	-	271
End of 2017	-	-	-	-	-	259	-	259
End of 2018	-	-	-	-	-	505	-	505

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.

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, 2018, included:

- Revisions: 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. In 2016, revisions in our equity affiliates in Asia Pacific/Middle East were primarily due to lower prices.

- *Purchases:* In 2018, Alaska purchases were due to the Kuparuk Assets and Western North Slope acquisitions.

- Extensions and discoveries: 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 Delaware, Eagle Ford and Bakken.

- Sales: 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.

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Years Ended December 31	Bitumen Millions of Barrels Canada
Developed and Undeveloped	
Consolidated operations	
End of 2015	687
Revisions	(515)
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(13)
Sales	-
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
Equity affiliates	
End of 2015	1,706
Revisions	(573)
Improved recovery	-
Purchases	-
Extensions and discoveries	10
Production	(54)
Sales	-
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	-
Total company	
End of 2015	2,393
End of 2016	1,248
End of 2017	250
End of 2018	236

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Years Ended December 31	Bitumen Millions of Barrels Canada
Developed	
Consolidated operations	
End of 2015	111
End of 2016	159
End of 2017	154
End of 2018	155
Equity affiliates	
End of 2015	311
End of 2016	322
End of 2017	-
End of 2018	-
Undeveloped	
Consolidated operations	
End of 2015	576
End of 2016	-
End of 2017	96
End of 2018	81
Equity affiliates	
End of 2015	1,395
End of 2016	767
End of 2017	-
End of 2018	-

Notable changes in proved bitumen reserves in the three years ended December 31, 2018, included:

- *Revisions*: In 2018, revisions were primarily due to higher prices at Surmont. In 2017, revisions were primarily due to higher prices at Surmont. In 2016, for both our consolidated operations and equity affiliates revisions were primarily related to lower prices which resulted in reserve reductions at Surmont, Foster Creek, Christina Lake and Narrows Lake.

- *Extensions and discoveries*: 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.

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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 2015	1,420	1,771	3,191	930	593	497	242	5,453
Revisions	(77)	(143)	(220)	(484)	11	9	-	(684)
Improved recovery	6	3	9	-	-	7	-	16
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	33	124	157	9	-	28	-	194
Production	(76)	(185)	(261)	(55)	(76)	(87)	(1)	(480)
Sales	(12)	-	(12)	(7)	-	(10)	-	(29)
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
Equity affiliates								
End of 2015	-	-	-	1,706	-	1,021	-	2,727
Revisions	-	-	-	(573)	-	(113)	-	(686)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	10	-	21	-	31
Production	-	-	-	(54)	-	(64)	-	(118)
Sales	-	-	-	-	-	-	-	-
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
Total company								
End of 2015	1,420	1,771	3,191	2,636	593	1,518	242	8,180
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

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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 2015	1,318	1,261	2,579	352	398	384	242	3,955
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
Equity affiliates								
End of 2015	-	-	-	311	-	890	-	1,201
End of 2016	-	-	-	322	-	820	-	1,142
End of 2017	-	-	-	-	-	802	-	802
End of 2018	-	-	-	-	-	796	-	796
Undeveloped								
Consolidated operations								
End of 2015	102	510	612	578	195	113	-	1,498
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
Equity affiliates								
End of 2015	-	-	-	1,395	-	131	-	1,526
End of 2016	-	-	-	767	-	45	-	812
End of 2017	-	-	-	-	-	43	-	43
End of 2018	-	-	-	-	-	84	-	84

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 1,162 million BOE of proved undeveloped reserves at year-end 2018, compared with 1,191 million BOE at year-end 2017. The following table shows changes in total proved undeveloped reserves for 2018:

	Proved Undeveloped Reserves
	Millions of Barrels of Oil Equivalent
End of 2017	1,191
Transfers to proved developed	(270)
Revisions	(208)
Improved recovery	2
Purchases	43
Extensions and discoveries	445
Sales	(41)
End of 2018	1,162

Downward revisions were primarily in our Lower 48 segment and were mainly due to changes in development timing for specific well locations from the unconventional plays. These revisions were partially offset by higher prices in Lower 48 as well as Alaska, Europe and APME.

Extensions and discoveries were primarily in Lower 48 and were mainly due to changes in the development strategy to add specific well locations from the unconventional plays.

Purchases were due to the Kuparuk Assets and Western North Slope acquisitions in Alaska. Sales were primarily due to the disposition of a subsidiary that held a 16.5 percent interest in the Clair Field in the United Kingdom.

At December 31, 2018, our proved undeveloped reserves represented 22 percent of total proved reserves, compared with 24 percent at December 31, 2017. Costs incurred for the year ended December 31, 2018, relating to the development of proved undeveloped reserves were $4.6 billion. A portion of our costs incurred each year relates to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

At the end of 2018, approximately 90 percent of total proved undeveloped reserves are currently 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 Europe and Asia Pacific/Middle East regions. All major development areas are currently producing and are expected to have proved undeveloped reserves convert to proved developed over time. Approximately 77 percent of our total proved undeveloped reserves at year-end 2018 are in North America, and all 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 2018, 2017 and 2016 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas (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.

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Results of Operations

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

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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)

Production costs excluding taxes have been revised to exclude the non-service components of pension related net periodic costs to conform to the current year's presentation.

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Year Ended December 31, 2016	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars								
Consolidated operations									
Sales	$ 2,793	4,117	6,910	661	2,678	2,350	-	-	12,599
Transfers	8	-	8	-	-	347	-	-	355
Transportation costs	(676)	-	(676)	-	-	(40)	-	-	(716)
Other revenues	375	111	486	48	(34)	(25)	147	9	631
Total revenues	2,500	4,228	6,728	709	2,644	2,632	147	9	12,869
Production costs excluding taxes	996	1,852	2,848	781	786	626	23	(2)	5,062
Taxes other than income taxes	231	308	539	55	31	30	1	-	656
Exploration expenses	45	1,227	1,272	332	90	38	138	41	1,911
Depreciation, depletion and amortization	738	4,167	4,905	881	1,390	1,402	2	-	8,580
Impairments	1	148	149	88	(161)	44	-	-	120
Other related expenses	52	70	122	(51)	(77)	(13)	4	4	(11)
Accretion	52	72	124	32	210	35	-	-	401
	385	(3,616)	(3,231)	(1,409)	375	470	(21)	(34)	(3,850)
Income tax provision (benefit)	(7)	(1,307)	(1,314)	(406)	3	250	(72)	(13)	(1,552)
Results of operations	$ 392	(2,309)	(1,917)	(1,003)	372	220	51	(21)	(2,298)
Equity affiliates									
Sales	$ -	-	-	860	-	449	-	-	1,309
Transfers	-	-	-	-	-	825	-	-	825
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	(2)	-	-	(2)
Total revenues	-	-	-	860	-	1,272	-	-	2,132
Production costs excluding taxes	-	-	-	431	-	256	-	-	687
Taxes other than income taxes	-	-	-	15	-	476	-	-	491
Exploration expenses	-	-	-	6	-	-	-	-	6
Depreciation, depletion and amortization	-	-	-	309	-	548	-	-	857
Impairments	-	-	-	9	-	-	-	-	9
Other related expenses	-	-	-	(7)	-	8	-	24	25
Accretion	-	-	-	8	-	7	-	-	15
	-	-	-	89	-	(23)	-	(24)	42
Income tax provision (benefit)	-	-	-	24	-	(201)	-	-	(177)
Results of operations	$ -	-	-	65	-	178	-	(24)	219

Production costs excluding taxes have been revised to exclude the non-service components of pension related net periodic costs to conform to the current year's presentation.

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Statistics

Net Production	**2018**	2017	2016
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**171**	167	163
Lower 48	**229**	180	195
United States	**400**	347	358
Canada	**1**	3	7
Europe	**113**	122	120
Asia Pacific/Middle East	**89**	93	97
Africa	**36**	20	2
Total consolidated operations	**639**	585	584
Equity affiliates			
Asia Pacific/Middle East	**14**	14	14
Other areas	**-**	-	-
Total equity affiliates	**14**	14	14
Total company	**653**	599	598
Natural Gas Liquids			
Consolidated operations			
Alaska	**14**	14	12
Lower 48	**69**	69	88
United States	**83**	83	100
Canada	**1**	9	23
Europe	**8**	8	7
Asia Pacific/Middle East	**3**	4	7
Total consolidated operations	**95**	104	137
Equity affiliates—Asia Pacific/Middle East	**7**	7	8
Total company	**102**	111	145
Bitumen			
Consolidated operations—Canada	**66**	59	35
Equity affiliates—Canada	**-**	63	148
Total company	**66**	122	183
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**6**	7	25
Lower 48	**596**	898	1,219
United States	**602**	905	1,244
Canada	**12**	187	524
Europe	**475**	476	459
Asia Pacific/Middle East	**626**	687	730
Africa	**28**	8	1
Total consolidated operations	**1,743**	2,263	2,958
Equity affiliates—Asia Pacific/Middle East	**1,031**	1,007	899
Total company	**2,774**	3,270	3,857

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Average Sales Prices	2018	2017	2016
Crude Oil Per Barrel			
Consolidated operations			
Alaska	**$ 60.23**	42.69	31.68
Lower 48	**62.99**	47.36	37.49
United States	**61.75**	45.01	34.70
Canada	**48.73**	43.69	35.25
Europe	**70.98**	54.04	43.66
Asia Pacific/Middle East	**70.93**	54.38	42.23
Africa	**69.83**	55.11	-
Total international	**70.67**	54.16	42.76
Total consolidated operations	**65.01**	48.70	37.67
Equity affiliates			
Asia Pacific/Middle East	**72.49**	54.76	44.11
Total equity affiliates	**72.49**	54.76	44.11
Total operations	**65.17**	48.84	37.82
Natural Gas Liquids Per Barrel			
Consolidated operations			
Lower 48	**$ 27.30**	22.20	14.34
United States	**27.30**	22.20	14.34
Canada	**43.70**	21.51	14.82
Europe	**36.87**	34.07	22.62
Asia Pacific/Middle East	**47.20**	41.37	29.00
Total international	**40.00**	30.34	19.06
Total consolidated operations	**29.03**	24.21	15.72
Equity affiliates—Asia Pacific/Middle East	**45.69**	38.74	31.13
Total operations	**30.48**	25.22	16.68
Bitumen Per Barrel			
Consolidated operations—Canada	**$ 22.29**	21.43	12.91
Equity affiliates—Canada	**-**	23.83	15.80
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 2.48**	2.72	5.22
Lower 48	**2.82**	2.73	2.20
United States	**2.82**	2.73	2.24
Canada	**1.00**	1.93	1.49
Europe	**7.79**	5.72	4.71
Asia Pacific/Middle East	**5.95**	4.66	4.15
Africa	**4.84**	3.53	-
Total international	**6.64**	4.64	3.49
Total consolidated operations	**5.33**	3.87	2.97
Equity affiliates—Asia Pacific/Middle East	**6.06**	4.27	2.97
Total operations	**5.60**	4.00	2.97

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.

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	2018	2017	2016
Average Production Costs Per Barrel of Oil Equivalent*			
Consolidated operations			
Alaska	**$ 14.20**	14.26	15.20
Lower 48	**10.58**	11.03	10.41
United States	**11.73**	12.04	11.70
Canada	**16.32**	16.22	14.04
Europe	**11.73**	10.09	10.58
Asia Pacific/Middle East	**9.03**	7.31	7.57
Africa	**4.14**	5.74	31.42
Total international	**10.72**	9.99	10.38
Total consolidated operations	**11.26**	11.05	11.08
Equity affiliates			
Canada	**-**	7.57	7.96
Asia Pacific/Middle East	**4.56**	5.26	4.04
Other areas	**-**	-	-
Total equity affiliates	**4.56**	5.84	5.85
Average Production Costs Per Barrel—Bitumen			
Consolidated operations—Canada	**$ 13.59**	14.63	24.59
Equity affiliates—Canada	**-**	18.74	7.96
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 5.26**	4.14	3.53
Lower 48	**2.98**	2.18	1.73
United States	**3.71**	2.80	2.21
Canada	**0.82**	0.89	0.99
Europe	**0.45**	0.42	0.42
Asia Pacific/Middle East	**1.33**	0.50	0.36
Africa	**0.20**	0.26	1.37
Total international	**0.82**	0.53	0.55
Total consolidated operations	**2.37**	1.70	1.44
Equity affiliates			
Canada	**-**	0.30	0.28
Asia Pacific/Middle East	**11.41**	8.76	7.52
Other areas	**-**	-	-
Total equity affiliates	**11.41**	6.64	4.18
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 9.07**	10.99	11.26
Lower 48	**15.73**	18.44	23.43
United States	**13.60**	16.10	20.15
Canada	**12.25**	11.76	15.84
Europe	**14.66**	16.18	18.71
Asia Pacific/Middle East	**16.58**	16.58	16.95
Africa	**2.21**	2.09	2.73
Total international	**14.06**	14.96	17.22
Total consolidated operations	**13.82**	15.55	18.78
Equity affiliates			
Canada	**-**	6.52	5.70
Asia Pacific/Middle East	**9.09**	8.94	8.65
Other areas	**-**	-	-
Total equity affiliates	**9.09**	8.34	7.29

*Includes bitumen.

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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, 2018, 2017 and 2016. 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 coalbed methane test wells located in Asia Pacific/Middle East.

Net Wells Completed	Productive			Dry		
	2018	2017	2016	**2018**	2017	2016
Exploratory						
Consolidated operations						
Alaska	**6**	-	2	**-**	-	1
Lower 48	**45**	13	8	**1**	3	1
United States	**51**	13	10	**1**	3	2
Canada	**2**	13	8	**-**	-	1
Europe	*	*	*	*	*	1
Asia Pacific/Middle East	**2**	1	1	**-**	1	-
Africa	**-**	-	1	*	-	-
Other areas	**-**	-	-	**-**	1	-
Total consolidated operations	**55**	27	20	**1**	5	4
Equity affiliates						
Asia Pacific/Middle East	**6**	14	20	**-**	-	-
Total equity affiliates	**6**	14	20	**-**	-	-
Development						
Consolidated operations						
Alaska	**11**	9	9	**-**	-	-
Lower 48	**254**	161	119	**-**	-	-
United States	**265**	170	128	**-**	-	-
Canada	**1**	13	47	**-**	-	2
Europe	**9**	7	7	**-**	-	-
Asia Pacific/Middle East	**12**	8	6	**-**	-	-
Africa	**1**	-	-	**-**	-	-
Other areas	**-**	-	-	**-**	-	-
Total consolidated operations	**288**	198	188	**-**	-	2
Equity affiliates						
Canada	**-**	19	48	**-**	-	-
Asia Pacific/Middle East	**75**	84	108	**-**	-	-
Other areas	**-**	-	-	**-**	-	-
Total equity affiliates	**75**	103	156	**-**	-	-

**Our total proportionate interest was less than one.*

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The table below represents the status of our wells drilling at December 31, 2018, 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, 2018.

Wells at December 31, 2018			Productive*			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	5	5	1,692	1,012	-	-
Lower 48	330	177	9,749	4,507	4,339	1,647
United States	335	182	11,441	5,519	4,339	1,647
Canada	15	14	183	92	33	29
Europe	15	2	497	86	155	52
Asia Pacific/Middle East	9	4	386	161	58	29
Africa	8	1	830	135	9	2
Total consolidated operations	382	203	13,337	5,993	4,594	1,759
Equity affiliates						
Asia Pacific/Middle East	328	79	-	-	3,950	987
Total equity affiliates	328	79	-	-	3,950	987

**Includes 18 gross and 6 net multiple completion wells.*

Acreage at December 31, 2018	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	675	464	1,408	1,255
Lower 48	2,429	1,962	10,322	8,378
United States	3,104	2,426	11,730	9,633
Canada	200	119	3,267	1,793
Europe	787	231	2,730	807
Asia Pacific/Middle East	1,597	742	12,065	6,806
Africa	358	58	12,545	2,049
Other areas	-	-	560	323
Total consolidated operations	6,046	3,576	42,897	21,411
Equity affiliates				
Asia Pacific/Middle East	947	219	4,198	969
Total equity affiliates	947	219	4,198	969

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Costs Incurred

Year Ended December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East *	Africa	Other Areas	Total
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
2016									
Consolidated operations									
Unproved property acquisition	$ -	127	127	59	-	-	-	-	186
Proved property acquisition	-	5	5	19	-	-	-	-	24
	-	132	132	78	-	-	-	-	210
Exploration	110	656	766	286	65	52	215	67	1,451
Development	720	782	1,502	209	62	387	6	-	2,166
	$ 830	1,570	2,400	573	127	439	221	67	3,827
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	2	-	-	2
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	2	-	-	2
Exploration	-	-	-	15	-	19	-	-	34
Development	-	-	-	367	-	320	-	-	687
	$ -	-	-	382	-	341	-	-	723

** Certain amounts in Asia Pacific/Middle East equity affiliates have been revised in 2016 to reflect additional abandonment obligations.*

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Capitalized Costs

At December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
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
2017									
Consolidated operations									
Proved property	$ 18,149	35,332	53,481	6,217	27,221	14,236	889	-	102,044
Unproved property	1,068	1,137	2,205	985	290	822	122	67	4,491
	19,217	36,469	55,686	7,202	27,511	15,058	1,011	67	106,535
Accumulated depreciation, depletion and amortization	9,497	24,211	33,708	1,582	18,068	8,916	312	9	62,595
	$ 9,720	12,258	21,978	5,620	9,443	6,142	699	58	43,940
Equity affiliates									
Proved property	$ -	-	-	-	-	9,750	-	-	9,750
Unproved property	-	-	-	-	-	2,215	-	-	2,215
	-	-	-	-	-	11,965	-	-	11,965
Accumulated depreciation, depletion and amortization	-	-	-	-	-	5,342	-	-	5,342
	$ -	-	-	-	-	6,623	-	-	6,623

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

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
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

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	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 (benefit)	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

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	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2016								
Consolidated operations								
Future cash inflows	$ 29,697	31,963	61,660	4,739	18,533	12,770	10,715	108,417
Less:								
Future production costs	24,965	16,936	41,901	5,103	7,469	5,288	1,420	61,181
Future development costs	7,961	8,932	16,893	1,586	9,949	2,777	537	31,742
Future income tax provisions	-	744	744	-	(325)	1,563	7,885	9,867
Future net cash flows	(3,229)	5,351	2,122	(1,950)	1,440	3,142	873	5,627
10 percent annual discount	(3,143)	976	(2,167)	(1,297)	(2)	572	370	(2,524)
Discounted future net cash flows	$ (86)	4,375	4,289	(653)	1,442	2,570	503	8,151
Equity affiliates								
Future cash inflows	$ -	-	-	15,139	-	17,829	-	32,968
Less:								
Future production costs	-	-	-	8,514	-	10,620	-	19,134
Future development costs	-	-	-	4,993	-	980	-	5,973
Future income tax provisions	-	-	-	164	-	1,309	-	1,473
Future net cash flows	-	-	-	1,468	-	4,920	-	6,388
10 percent annual discount	-	-	-	540	-	1,911	-	2,451
Discounted future net cash flows	$ -	-	-	928	-	3,009	-	3,937
Total company								
Discounted future net cash flows	$ (86)	4,375	4,289	275	1,442	5,579	503	12,088

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Discounted future net cash flows at the beginning of the year	**$ 20,609**	8,151	16,562	**4,395**	3,937	9,027	**25,004**	12,088	25,589
Changes during the year									
Revenues less production costs for the year	**(14,909)**	(9,844)	(6,313)	**(1,651)**	(1,341)	(956)	**(16,560)**	(11,185)	(7,269)
Net change in prices and production costs	**25,391**	19,310	(16,476)	**4,559**	2,750	(9,317)	**29,950**	22,060	(25,793)
Extensions, discoveries and improved recovery, less estimated future costs	**4,574**	1,445	1,358	**382**	(4)	(77)	**4,956**	1,441	1,281
Development costs for the year	**5,197**	3,653	3,118	**271**	426	722	**5,468**	4,079	3,840
Changes in estimated future development costs	**(1,141)**	1,225	6,646	**14**	(64)	2,435	**(1,127)**	1,161	9,081
Purchases of reserves in place, less estimated future costs	**3,033**	-	2	**-**	-	-	**3,033**	-	2
Sales of reserves in place, less estimated future costs	**(1,531)**	(855)	(123)	**-**	(786)	-	**(1,531)**	(1,641)	(123)
Revisions of previous quantity estimates	**(365)**	2,300	(3,252)	**62**	(648)	(436)	**(303)**	1,652	(3,688)
Accretion of discount	**3,055**	1,313	2,540	**485**	413	1,058	**3,540**	1,726	3,598
Net change in income taxes	**(8,479)**	(6,089)	4,089	**(588)**	(288)	1,481	**(9,067)**	(6,377)	5,570
Total changes	**14,825**	12,458	(8,411)	**3,534**	458	(5,090)	**18,359**	12,916	(13,501)
Discounted future net cash flows at year end	**$ 35,434**	20,609	8,151	**7,929**	4,395	3,937	**43,363**	25,004	12,088

- 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
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**
2017						
First	$ 7,518	(232)	599	586	0.47	0.47
Second	6,781	(4,361)	(3,426)	(3,440)	(2.78)	(2.78)
Third	6,688	653	436	420	0.35	0.34
Fourth	8,119	1,325	1,598	1,579	1.32	1.32

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 December 2018, ConocoPhillips Canada Funding Company I's guaranteed, publicly held debt securities were assumed by Burlington Resources LLC. The assumption did not significantly change the nature of the outstanding debt or the terms of the parental guarantees, which remain full and unconditional, as well as joint and several. The assumption did not impact our consolidated financial position, results of operations or cash flows. Financial information for ConocoPhillips Canada Funding Company I is presented in the "All Other Subsidiaries" column of our condensed consolidating financial information. The prior year comparative periods have been restated to reflect the current period condensed consolidating financial information presentation.

In 2016, ConocoPhillips received a $2.3 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips Canada Funding Company I repaid $1.25 billion of external debt. This transaction was reflected in the full-year 2016 condensed consolidating financial statements.

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.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

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Income Statement	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	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
Income Statement	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)

**Certain amounts have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07. See Note 2—Changes in Accounting Principles, for additional information.*
See Notes to Consolidated Financial Statements.

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Income Statement	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2016*					
Revenues and Other Income						
Sales and other operating revenues	$ -	10,352	-	13,341	-	23,693
Equity in earnings (losses) of affiliates	(3,351)	(1,051)	(2,270)	61	6,663	52
Gain on dispositions	-	120	-	240	-	360
Other income (loss)	1	(11)	-	265	-	255
Intercompany revenues	88	277	21	2,995	(3,381)	-
Total Revenues and Other Income	(3,262)	9,687	(2,249)	16,902	3,282	24,360
Costs and Expenses						
Purchased commodities	-	9,144	-	3,562	(2,712)	9,994
Production and operating expenses	-	754	1	5,130	(242)	5,643
Selling, general and administrative expenses	8	331	-	140	(6)	473
Exploration expenses	-	1,229	-	683	-	1,912
Depreciation, depletion and amortization	-	1,178	-	7,884	-	9,062
Impairments	-	67	-	72	-	139
Taxes other than income taxes	-	162	-	577	-	739
Accretion on discounted liabilities	-	46	-	379	-	425
Interest and debt expense	506	622	37	501	(421)	1,245
Foreign currency transaction (gains) losses	(19)	2	(110)	108	-	(19)
Other expenses	-	277	-	-	-	277
Total Costs and Expenses	495	13,812	(72)	19,036	(3,381)	29,890
Loss before income taxes	(3,757)	(4,125)	(2,177)	(2,134)	6,663	(5,530)
Income tax benefit	(142)	(774)	(92)	(963)	-	(1,971)
Net loss	(3,615)	(3,351)	(2,085)	(1,171)	6,663	(3,559)
Less: net income attributable to noncontrolling interests	-	-	-	(56)	-	(56)
Net Loss Attributable to ConocoPhillips	$ (3,615)	(3,351)	(2,085)	(1,227)	6,663	(3,615)
Comprehensive Loss Attributable to ConocoPhillips	$ (3,561)	(3,297)	(1,641)	(1,149)	6,087	(3,561)

**Certain amounts have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07. See Note 2—Changes in Accounting Principles, for additional information.*
See Notes to Consolidated Financial Statements.

Balance Sheet	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	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
Balance Sheet	At December 31, 2017					
Assets						
Cash and cash equivalents	$ -	234	3	6,088	-	6,325
Short-term investments	-	-	-	1,873	-	1,873
Accounts and notes receivable	24	2,214	294	4,910	(3,122)	4,320
Investment in Cenovus Energy	-	1,899	-	-	-	1,899
Inventories	-	163	-	897	-	1,060
Prepaid expenses and other current assets	1	277	24	763	(30)	1,035
Total Current Assets	25	4,787	321	14,531	(3,152)	16,512
Investments, loans and long-term receivables*	29,400	47,974	12,273	14,547	(94,134)	10,060
Net properties, plants and equipment	-	4,230	-	41,930	(477)	45,683
Other assets	15	1,146	672	1,043	(1,769)	1,107
Total Assets	$ 29,440	58,137	13,266	72,051	(99,532)	73,362
Liabilities and Stockholders' Equity						
Accounts payable	$ -	3,094	264	3,794	(3,122)	4,030
Short-term debt	(5)	2,505	7	77	(9)	2,575
Accrued income and other taxes	-	65	-	973	-	1,038
Employee benefit obligations	-	554	-	171	-	725
Other accruals	85	314	17	642	(29)	1,029
Total Current Liabilities	80	6,532	288	5,657	(3,160)	9,397
Long-term debt	3,787	9,321	500	3,998	(478)	17,128
Asset retirement obligations and accrued environmental costs	-	432	-	7,199	-	7,631
Deferred income taxes	-	-	-	6,490	(1,208)	5,282
Employee benefit obligations	-	1,335	-	519	-	1,854
Other liabilities and deferred credits*	1,528	5,229	1,446	10,135	(17,069)	1,269
Total Liabilities	5,395	22,849	2,234	33,998	(21,915)	42,561
Retained earnings	22,892	13,342	(753)	7,669	(13,759)	29,391
Other common stockholders' equity	1,153	21,946	11,785	30,190	(63,858)	1,216
Noncontrolling interests	-	-	-	194	-	194
Total Liabilities and Stockholders' Equity	$ 29,440	58,137	13,266	72,051	(99,532)	73,362

*Includes intercompany loans.

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Statement of Cash Flows	Millions of Dollars					
	Year Ended December 31, 2018					
	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by Operating Activities	$ 4,317	4,183	2,764	14,132	(12,462)	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	-	502	-	705	(125)	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	(214)	6,373	(2,714)	(3,839)	(3,449)	(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

Statement of Cash Flows	Year Ended December 31, 2017					
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

**Restated to include $211 million of restricted cash at January 1, 2018. See Note 2—Changes in Accounting Principles for additional information relating to the adoption of ASU No. 2016-18.*
Restricted cash totaling $236 million is included in the "Other assets" line of our Consolidated Balance Sheet as of December 31, 2018.

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Statement of Cash Flows	Millions of Dollars					
	Year Ended December 31, 2016					
	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ (306)	(322)	799	5,902	(1,670)	4,403
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(989)	(1,714)	(4,281)	2,115	(4,869)
Working capital changes associated with investing activities	-	(126)	-	(205)	-	(331)
Proceeds from asset dispositions	2,300	266	-	1,114	(2,394)	1,286
Net purchases of short-term investments	-	-	-	(51)	-	(51)
Long-term advances/loans—related parties	-	(812)	-	-	812	-
Collection of advances/loans—related parties	-	391	-	272	(555)	108
Intercompany cash management	(2,214)	1,433	912	(131)	-	-
Other	-	1	-	(3)	-	(2)
Net Cash Provided by (Used in) Investing Activities	86	164	(802)	(3,285)	(22)	(3,859)
Cash Flows From Financing Activities						
Issuance of debt	1,600	2,994	-	812	(812)	4,594
Repayment of debt	(150)	(164)	-	(2,492)	555	(2,251)
Issuance of company common stock	148	-	-	-	(211)	(63)
Repurchase of company common stock	(126)	-	-	-	-	(126)
Dividends paid	(1,253)	-	-	(1,881)	1,881	(1,253)
Other	1	(2,315)	-	1,898	279	(137)
Net Cash Provided by (Used in) Financing Activities	220	515	-	(1,663)	1,692	764
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	(3)	2	(65)	-	(66)
Net Change in Cash and Cash Equivalents	-	354	(1)	889	-	1,242
Cash and cash equivalents at beginning of period	-	4	6	2,358	-	2,368
Cash and Cash Equivalents at End of Period	$ -	358	5	3,247	-	3,610

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, 2018, 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, 2018.

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 82 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 84 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 pages 29 and 30.

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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2019, 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 2019 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.*

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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 81, 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 190 through 199, are filed as part of this annual report.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

	Millions of Dollars				
Description	Balance at January 1	Charged to Expense	Other(a)	Deductions	Balance at December 31
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
2016					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 7	3	(1)	(4)(b)	5
Deferred tax asset valuation allowance	734	(31)	(12)	(16)	675
Included in other liabilities:					
Restructuring accruals	156	129	1	(206)(c)	80

(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.

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.
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	Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.10.2	First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated July 20, 2015 (incorporated by reference to Exhibit 10.10.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.10.3	Second Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated March 14, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.10.4	Eighth Amendment to Retirement Plan 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	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.2	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.3	First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).

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Exhibit Number	Description
10.11.4	Second Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated December 17, 2015 (incorporated by reference to Exhibit 10.11.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
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).
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).
10.17.1	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).
10.17.2	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).
10.17.3	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).
10.17.4	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).
10.17.5	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).
10.17.6	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).
10.17.7	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).
10.17.8	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).

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Exhibit Number	Description
10.18.1	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).
10.18.2	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).
10.19	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).
10.20.1	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated April 19, 2012 (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).
10.20.2	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated April 19, 2012 (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).
10.20.3	First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.4	Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.5	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, 2013 Restatement dated November 17, 2014 (Amended and Restated effective as of January 1, 2013) (incorporated by reference to Exhibit 10.20.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2014; File No. 001-32395).
10.21	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).
10.22	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).
10.23.1	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).
10.23.2	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).

Exhibit Number	Description
10.23.3	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).
10.24	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).
10.25	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).
10.26.1	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).
10.26.2	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).
10.26.5	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).
10.26.6	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).
10.26.7	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).
10.26.8	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).
10.26.9	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).
10.26.10	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).

Exhibit Number	Description
10.26.11	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).
10.26.12	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).
10.26.13	Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.14	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).
10.26.15	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).
10.26.16	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).
10.26.17	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).
10.26.18	Form of Performance Period X 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 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.19	Form of Performance Period XII 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 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).

Exhibit Number	Description
10.26.20	Form of Performance Period XII 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 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.21	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).
10.26.22	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).
10.26.23	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).
10.26.24	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).
10.26.25	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).
10.27.1	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).
10.27.3	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).
10.27.4	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).
10.27.5	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).

Exhibit Number	Description
10.27.6	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 Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.27.7	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).
10.27.8	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).
10.27.9	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).
10.27.10	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).
10.27.11	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).
10.27.12	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).
10.27.13	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).
10.27.14	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).
10.27.15	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
10.27.16*	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.
10.28	Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (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).
10.29	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).
10.30	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).
10.31	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).
10.32	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).
10.33	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).
10.34	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).
10.35	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).
10.36	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).
10.37	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).
10.38	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).
10.39*	Company Retirement Contribution Make-up Plan of ConocoPhillips, dated December 28, 2018.
21*	List of Subsidiaries of ConocoPhillips.
23.1*	Consent of Ernst & Young LLP.

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Exhibit Number	Description
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*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* *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.*

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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 19, 2019	*/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 19, 2019, 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)

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/s/ Charles E. Bunch	Director
Charles E. Bunch	
/s/ Caroline M. Devine	Director
Caroline M. Devine	
/s/ Gay Huey Evans	Director
Gay Huey Evans	
/s/ John V. Faraci	Director
John V. Faraci	
/s/ Jody Freeman	Director
Jody Freeman	
/s/ Jeffrey A. Joerres	Director
Jeffrey A. Joerres	
/s/ William H. McRaven	Director
William H. McRaven	
/s/ Sharmila Mulligan	Director
Sharmila Mulligan	
/s/ Arjun N. Murti	Director
Arjun N. Murti	
/s/ Robert A. Niblock	Director
Robert A. Niblock	
/s/ Harald J. Norvik	Director
Harald J. Norvik	

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2017

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, 2017**

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.)*

600 North Dairy Ashford
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	**Name of each exchange on which registered**
Common Stock, $.01 Par Value	New York Stock Exchange
7% Debentures due 2029	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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
[x] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer [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 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $43.96, was $54.0 billion.

The registrant had 1,174,577,506 shares of common stock outstanding at January 31, 2018.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 15, 2018 (Part III)

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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 heading “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 the world’s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. 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.

In April 2012, ConocoPhillips completed the separation of the downstream business into an independent, publicly traded energy company, Phillips 66.

Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our diverse portfolio includes resource-rich North American tight oil and oil sands assets; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects.

At December 31, 2017, ConocoPhillips employed approximately 11,400 people worldwide.

We operate in a commodity-price driven industry, subject to volatility. In line with this view, we set our operating plan for 2017, defining our cash allocation priorities which would be reinforced and partly funded by sales of noncore assets during the year. In November 2016, we announced our plan to generate $5 billion to $8 billon of proceeds over two years by optimizing our portfolio to focus on value-preserving, low cost-of-supply projects that strategically fit our development plans. In 2017, our total consideration from asset dispositions was approximately $16 billion. We disposed of assets including our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets, and our interest in the San Juan Basin gas asset. Proceeds from dispositions were directed towards our cash allocation priorities and for general corporate purposes. For additional information on our cash allocation priorities and our asset sales, see the Business Environment and Executive Overview section within Management’s Discussion and Analysis and Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements, respectively.

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SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 23—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 natural gas liquids on a worldwide basis. At December 31, 2017, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

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, natural gas liquids, natural gas and bitumen reserves.
- Net production of crude oil, natural gas liquids, natural gas and bitumen.
- Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.
- Average production costs per barrel of oil equivalent (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 77 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 thousand cubic feet (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	**2017**	2016	2015
Crude oil			
Consolidated operations	**2,322**	2,047	2,270
Equity affiliates	**83**	88	93
Total Crude Oil	**2,405**	2,135	2,363
Natural gas liquids			
Consolidated operations	**354**	457	508
Equity affiliates	**45**	47	50
Total Natural Gas Liquids	**399**	504	558
Natural gas			
Consolidated operations	**1,267**	1,807	1,988
Equity affiliates	**717**	730	878
Total Natural Gas	**1,984**	2,537	2,866
Bitumen			
Consolidated operations	**250**	159	687
Equity affiliates	**-**	1,089	1,706
Total Bitumen	**250**	1,248	2,393
Total consolidated operations	**4,193**	4,470	5,453
Total equity affiliates	**845**	1,954	2,727
Total company	**5,038**	6,424	8,180

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Total production, including Libya, of 1,377 thousand barrels of oil equivalent per day (MBOED) decreased 12 percent in 2017 compared with 2016. The decrease in total average production primarily resulted from noncore asset dispositions, including our Canada and San Juan transactions in 2017 and the sale of our interest in the Block B production sharing contract (PSC) in Indonesia in 2016, and normal field decline. The decrease in production was partly offset by production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont in Canada; and APLNG in Australia. Improved drilling and well performance in Alaska, Norway and China also partly offset the decrease in production. Excluding Libya, our 2017 production was 1,356 MBOED. Adjusted for the impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, underlying production increased 32 MBOED, or 3 percent, compared with 2016.

Our worldwide annual average realized price was $39.19 per BOE in 2017, an increase of 38 percent compared with $28.35 per BOE in 2016, reflecting higher average realized prices across all commodities. Our worldwide annual average crude oil price increased 27 percent in 2017, from $40.86 per barrel in 2016 to $51.96 per barrel in 2017. Additionally, our worldwide annual average natural gas liquids prices increased 51 percent, from $16.68 per barrel in 2016 to $25.22 per barrel in 2017. Our worldwide annual average natural gas price increased 36 percent, from $3.00 per MCF in 2016 to $4.07 per MCF in 2017. Average annual bitumen prices also increased 48 percent, from $15.27 per barrel in 2016 to $22.66 per barrel in 2017.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids. 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 significant operating 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 million net undeveloped acres at year-end 2017. Alaska operations contributed 22 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

			2017		
	Interest	Operator	Liquids MBD *	Natural Gas MMCFD **	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1 %	BP	88	5	89
Greater Kuparuk Area	52.2–55.5	ConocoPhillips	53	1	53
Western North Slope	78.0	ConocoPhillips	40	1	40
Total Alaska			181	7	182

**Thousands of barrels per day.*
***Millions of cubic feet per day.*

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 natural gas liquids 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.

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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.

Drill Site 2S, in the southwestern area of the Kuparuk Field, was sanctioned in October 2014. First oil was achieved in October 2015, and completion of the first phase of the project was achieved in 2016.

The 1H Northeast West Sak (NEWS) oil development targeting the West Sak reservoir in the Kuparuk River Unit, was sanctioned in March 2015. First production was achieved in the fourth quarter of 2017.

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 new drill site which extends the Alpine reservoir west into the National Petroleum Reserve-Alaska (NPR-A). During the year, we continued drilling additional wells using the available well slots on the 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, which is currently planned to have two drill sites; Greater Mooses Tooth #1 and #2, with expected first oil in 2018 and 2021, respectively.

Cook Inlet Area
In January 2018, we sold our interest in the Kenai LNG Facility in the Cook Inlet Area. The facility, which consisted of a 1.6 million-tons-per-year capacity plant, as well as docking and loading facilities for LNG tankers, had no LNG export program in 2017 due to market conditions.

Point Thomson
In the first quarter of 2017, we recorded an asset impairment and assigned our 4.9 percent interest in the Point Thomson unit, located approximately 60 miles east of Prudhoe Bay, to the other owners of the field.

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 (collectively, the “AKLNG co-venturers”), completed preliminary front-end engineering and design (pre-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 September 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 is continuing to progress the project and has recently signed several Memorandums of Understanding with various potential LNG buyers in Asia. We remain supportive of AGDC’s efforts to advance the project and intend to make our equity gas available for sale to the project at mutually agreed, commercially reasonable terms.

Exploration
Appraisal of the Willow Discovery, located in the northeast portion of the National Petroleum Reserve-Alaska, continued throughout 2017 with the acquisition of 3-D seismic which is currently being processed. In 2018, we will continue appraisal of the discovery with drilling of additional wells. Further exploration of other state and federal leases is planned in 2018.

We were successful in state and federal lease sales in the North Slope in the fourth quarter of 2017, where we were the high bidder on 13 tracts for a total of approximately 78,000 net acres.

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Acquisition
In January 2018, we entered into an agreement to acquire certain oil and gas assets in Alaska. The acquisition is subject to regulatory approval. We will have a 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery. For additional information, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

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 United States.

LOWER 48

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and the Gulf of Mexico. The Lower 48 business is organized within three regions covering the Gulf Coast, Mid-Continent and Rockies. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost-of-supply plays. We disposed of several noncore assets within the Lower 48 in 2017, including our interests in the San Juan Basin and the Panhandle. We hold 10.4 million net onshore and offshore acres in the Lower 48. In 2017, the Lower 48 contributed 30 percent of our worldwide liquids production and 27 percent of our natural gas production.

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various %	Various	107	155	133
Gulf of Mexico	Various	Various	15	13	17
Gulf Coast—Other	Various	Various	5	11	7
Total Gulf Coast			127	179	157
Permian	Various	Various	41	132	63
Barnett	Various	Various	4	34	10
Anadarko Basin	Various	Various	4	91	19
Total Mid-Continent			49	257	92
Bakken	Various	Various	56	56	65
Wyoming/Uinta	Various	Various	-	84	14
Niobrara	Various	Various	2	3	3
San Juan	Various	Various	15	319	68
Total Rockies			73	462	150
Total U.S. Lower 48			249	898	399

Onshore
We hold 10.4 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 1.8 million net acres in the following areas:

- 630,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 210,000 net acres in the Eagle Ford, located in South Texas.
- 134,000 net acres in the Permian, located in West Texas and southeastern New Mexico.

- 98,000 net acres in the Niobrara, located in northeastern Colorado.
- 66,000 net acres in the Barnett, located in north central Texas.
- 639,000 net acres in other unconventional exploration plays.

The majority of our 2017 onshore production originated from the Eagle Ford; San Juan, which we disposed of during the year; Bakken; and Permian. Onshore activities in 2017 were centered mostly on continued development of assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. The 2017 drilling activity levels increased relative to 2016 due to higher capital spending. Our major focus areas in 2017 included the following:

- Eagle Ford—The Eagle Ford continued full-field development in 2017. We operated six rigs on average in 2017, resulting in 133 operated wells drilled and 94 operated wells brought online. Production decreased 17 percent in 2017 compared with 2016, and reached a net peak of 164 MBOED, compared with 176 MBOED in 2016.
- Bakken—We operated four rigs throughout the year in the Bakken. We continued our pad drilling with 87 operated wells drilled during the year and 64 operated wells brought online. We achieved net peak production of 75 MBOED in 2017, compared with 72 MBOED in 2016.
- Permian Basin—The Permian Basin is an area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. This technology should also identify new, unconventional plays across the region. We hold approximately 1 million net acres in the Permian, which includes 134,000 net unconventional acres. The Permian Basin produced 63 MBOED in 2017, staying essentially flat with 2016, including 19 MBOED of unconventional production.

We completed the sale of our interests in the San Juan Basin on July 31, 2017, and Panhandle assets on September 29, 2017. Production from the assets sold was 74 MBOED, approximately 19 percent of total Lower 48 segment production in 2017. For additional information on our asset dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

Gulf of Mexico
At year-end 2017, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, totaling approximately 68,000 net acres, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 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.

Exploration

- *Conventional Exploration*

  At December 31, 2017, we held approximately 5,000 net acres in the deepwater Gulf of Mexico.

  Our 30 percent nonoperated working interest in the Shenandoah discovery was announced in 2009. In early 2017, the sixth Shenandoah well, Shenandoah WR52-3, reached total depth and was followed by the drilling of a sidetrack well from Shenandoah WR52-3. Following the suspension of appraisal activity by the operator during the year, we recorded dry hole and leasehold impairment expense for the entire development. On December 19, 2017, we elected to withdraw from the Shenandoah leases. The withdrawal was effective February 17, 2018.

- *Unconventional Exploration*
  Our onshore focus areas include the Niobrara in the Denver-Julesburg Basin and the Permian in the Delaware Basin, as well as several emerging plays. We continue to assess and appraise these and other unconventional opportunities. In 2016 and 2017, we drilled a total of five operated unconventional wells in the Powder River Basin, four of which were expensed as dry holes in November 2017. The fifth Powder River Basin well was expensed as a dry hole in January 2018.

Facilities

Golden Pass LNG Terminal

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $247 million at December 31, 2017. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. As a result, we are evaluating opportunities to optimize the value of the terminal facilities.

Other

- Lost Cabin Gas Plant—We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 246 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 110,000 barrel-per-day 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 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

CANADA

Our Canadian operations mainly consist of an oil sands development in the Athabasca Region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2017, operations in Canada contributed 16 percent of our worldwide liquids production and 6 percent of our natural gas production.

			2017			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Western Canada	Various %	Various	12	187	-	43
Surmont	50.0	ConocoPhillips	-	-	59	59
Foster Creek	50.0	Cenovus	-	-	26	26
Christina Lake	50.0	Cenovus	-	-	37	37
Total Canada			12	187	122	165

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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. Production from the assets sold was 103 MBOED, approximately 62 percent of the total Canada segment production in 2017. For additional information on our asset dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

Oil Sands
Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (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.

Surmont—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 production continued to ramp up in 2017.

Exploration
We hold exploration acreage in three areas of Canada: onshore western Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada.

- *Unconventional Exploration*
  We hold approximately 0.1 million net acres in the emerging Montney play in northeast British Columbia and 0.2 million net acres in Canol Northwest Territories. Our Montney activity in 2017 included completing two and bringing onstream six appraisal wells and acquiring approximately 27,000 additional net acres. Late appraisal drilling activity will continue in 2018 to further explore the area's resource potential.

- *Conventional Exploration*
  Surrender of Interest documents for our 30 percent nonoperated working interest in six exploration licenses in the Shelburne Basin, offshore Nova Scotia, were submitted on December 15, 2017, to initiate the exit process, following previously announced results of the two-well exploration drilling campaign at Cheshire and Monterey Jack.

EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2017, operations in Europe and North Africa contributed 18 percent of our worldwide liquids production and 15 percent of natural gas production.

Norway

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1 %	ConocoPhillips	57	50	65
Alvheim	20.0	Aker BP	15	13	17
Heidrun	24.0	Statoil	13	30	18
Other	Various	Statoil	16	107	34
Total Norway			101	200	134

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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 which achieved first production in 2013 and 2015, respectively. Continued development drilling in the Greater Ekofisk Area will contribute additional production over the coming years, as additional wells come online.

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 floating production, storage and offloading (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.

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 to Europe via gas processing terminals in Norway, while the remainder is transported for use as feedstock in a methanol plant in Norway, in which we own an 18 percent interest.

We also have varying ownership interests in five other producing fields in the Norway sector of the North Sea, as well as the Aasta Hansteen development in the Norwegian Sea. The operator is planning for first gas for Aasta Hansteen by late 2018.

Exploration
In 2017, we participated in the Korpfjell Well in the Barents Sea and the Carmen Well in the Heidrun Area of Norway, both of which made gas discoveries. The Carmen Well was considered a discovery and is currently under evaluation, while the Korpfjell Well is not considered commercial. In 2017, we were awarded four new exploration licenses including the PL865, PL888, PL890 and PL891; and two acreage additions PL053C and PL782SC. Additionally, two new licenses, PL775 and PL626, were captured through farm-in.

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 natural gas liquids processing facility in Teesside, England.

United Kingdom

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Britannia	58.7 %	ConocoPhillips	3	68	14
Britannia Satellites	26.3–87.5 *	ConocoPhillips	13	84	27
J-Area	32.5–36.5	ConocoPhillips	9	60	19
Southern North Sea	Various	ConocoPhillips	-	46	8
East Irish Sea	100.0	Spirit Energy	-	14	2
Other	Various	Various	4	4	5
Total United Kingdom			29	276	75

** Includes the Chevron-operated Alder Field, ConocoPhillips equity 26.3%.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. We assumed operatorship of Britannia in August 2015, following the acquisition of third-party equity in Britannia Operator Limited, which is now wholly owned by ConocoPhillips. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia's line to St. Fergus, Scotland. The Britannia satellite fields, Callanish, Brodgar, Enochdhu and Alder, produce via subsea manifolds and pipelines linked to the Britannia Platform.

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The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The J-Area gas is processed on the Judy Platform and transported through the Central Area Transmission System Pipeline, while liquids are transported to Teesside through the Norpipe system. A J-Area development drilling campaign commenced in 2017, which is expected to provide additional volumes in the coming years as wells are brought online.

We have various ownership interests in several producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Decommissioning activity in the Southern North Sea is ongoing. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities will tie into existing oil and gas export pipelines to the Shetland Islands. Initial production for Clair Ridge is expected in 2018.

Transportation
We operate the Teesside oil and Theddlethorpe gas terminals in which we have 29.3 percent and 50 percent ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

Libya

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3 %	Waha Oil Co.	20	8	21
Total Libya			20	8	21

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 were interrupted in mid-2013, as a result of the shutdown of the Es Sider crude oil export terminal at the end of July 2013. The Es Sider Terminal briefly reopened in the third quarter of 2014 and production and liftings resumed temporarily; however, further disruptions occurred in December 2014, and production was shut in again. Production resumed in Libya in October 2016. In 2017, we had 17 crude liftings from Es Sider. We expect a gradual, continued ramp-up in activity.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia; producing operations in Qatar and Timor-Leste; and exploration activities in Brunei. In 2017, operations in the Asia Pacific and Middle East segment contributed 14 percent of our worldwide liquids production and 52 percent of natural gas production.

Australia and Timor Sea

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Australia Pacific LNG	37.5 %	ConocoPhillips/ Origin Energy	-	638	106
Bayu-Undan	56.9	ConocoPhillips	10	233	49
Athena/Perseus	50.0	ExxonMobil	-	34	6
Total Australia and Timor Sea			10	905	161

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 coalbed methane (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.

Two fully subscribed 4.5-million-metric-tonnes-per-year LNG trains have been completed. Approximately 3,900 net wells are ultimately envisioned to supply both the domestic gas market and the LNG sales contracts. 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 first APLNG Train 1 cargo sailed in January 2016, and LNG sales continued throughout the year. APLNG Train 2 achieved first production in the third quarter of 2016. 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.

APLNG has an $8.5 billion project finance facility, which was fully drawn down and had an outstanding balance of $7.9 billion at December 31, 2017. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for Train 2, which removed the remaining guarantee. For additional information, see Note 2—Variable Interest Entities (VIEs), Note 5—Investments, Loans and Long-Term Receivables, and Note 11—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 2017, we sold 150 billion gross cubic feet of LNG primarily to utility customers in Japan.

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A continuation of the Bayu-Undan Phase Three Development has been sanctioned with internal, joint venture and regulatory approval in March 2017. The project premise consists of one subsea and two platform wells, with drilling to commence in April 2018. Production is expected to commence in the third quarter of 2018.

Athena/Perseus
The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field, which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses, which are due to expire in 2019.

Greater Sunrise
We have a 30 percent interest in the Greater Sunrise natural gas and condensate field located in the Timor Sea. Timor-Leste and Australia through engagement in a conciliation process under the United Nations Convention on the Law of the Sea have reached agreement on the central elements of a maritime boundary delimitation between them in the Timor Sea. The Governments' agreement, to be formalized in a new treaty, constitutes a package that addresses boundaries, the legal status of the Greater Sunrise gas field, the establishment of a Special Regime for Greater Sunrise, a pathway to development of the resource and the sharing of resulting revenue. Discussions are ongoing between the two Governments and the Sunrise co-venturers with respect to the development concept for Greater Sunrise. Until the Governments and the Sunrise co-venturers are aligned on a development concept, activities are currently restricted to compliance and social investment, maintaining relationships and continued engagement with the Governments for a future development option.

Exploration

- *Conventional 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. The TP 28 Western Australia State exploration permit was granted for five years from January 2017, with a 40 percent working interest and was excised from the existing permits as agreed between state and federal regulators. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. All wells have been completed, plugged and abandoned.

  We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. A 3-D seismic survey was completed over the Barossa and Caldita fields in 2016. The drilling of the Barossa-5 and Barossa-6 appraisal wells was completed in 2017 with good quality, gas-bearing reservoir intersected at both. Additionally, the retention lease over the Barossa Discovery was renewed during the year.

Indonesia

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Sumatra	45.0–54.0 %	ConocoPhillips	2	308	53
Total Indonesia			2	308	53

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We operate three PSCs in Indonesia: The Corridor Block and South Jambi "B," both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently there is production from the Corridor Block.

South Sumatra
The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. 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. Production from the South Jambi "B" PSC has reached depletion and field development has been suspended.

Exploration
We have a 60 percent working interest in the Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 2 million gross acres. During 2017, we acquired 2-D seismic data in the area.

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

			2017		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Penglai	49.0 %	CNOOC	30	-	30
Panyu	24.5	CNOOC	8	-	8
Total China			38	-	38

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2 included six additional wellhead platforms and an FPSO vessel, and was fully operational by 2009.

As part of further development of the Penglai 19-9 Field, a new wellhead platform, which adds up to 62 wells, is progressing according to schedule, with 19 wells completed and brought online through December 2017.

We sanctioned the Penglai 19-3/19-9 Phase 3 Project in December 2015. This project will consist of three new wellhead platforms and a central processing platform. First oil from Phase 3 is expected in 2018.

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The production period for Panyu 4-2 and 5-1 will expire in 2018, and the production period for Panyu 11-6 will expire in 2022.

Exploration
In 2017, we participated in a successful appraisal well in the Penglai Field, which will support future development plans. In late 2017, we began a full-field 3-D seismic program at Penglai, covering Phase 3 and other future development opportunities. The program is expected to continue in 2018.

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Malaysia

	Interest		Operator	2017 Liquids MBD	2017 Natural Gas MMCFD	2017 Total MBOED
Average Daily Net Production						
Siakap North-Petai	21.0	%	Murphy	3	1	3
Gumusut	29.0		Shell	29	-	29
KBB	30.0		KPOC	3	111	22
Malikai	35.0		Shell	12	-	12
Total Malaysia				47	112	66

We own interests in six PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, Deepwater Block 3E, Block SK313 and Block WL4-00 are located off the eastern Malaysian state of Sarawak.

Block G
We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014.

First production from the Malikai oil field was achieved in December 2016, with estimated net annual peak production of 21 MBOED expected in 2018. We own a 35 percent interest in Malikai. The Limbayong-2 appraisal well was drilled in 2013 and resulted in an oil discovery. The well was expensed in 2017.

Block J
First production from the Gumusut Field occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014. Our ownership in the Gumusut Field is currently at 29 percent following the finalization of the unitization with Brunei and a redetermination of the Block J and Block K Malaysia Unit, both in 2017. Gumusut Phase 2 infill drilling is planned to start in 2018.

KBBC
We own a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Development options for the Kamunsu East gas field are being evaluated.

Exploration
We own a 50 percent operated interest in Deepwater Block 3E, which encompasses approximately 480,000 gross acres offshore Sarawak. Seismic processing was completed in 2015. The Langsat-1 exploration well was drilled and expensed as a dry hole in 2017.

In the fourth quarter of 2016, we entered into a farm-in agreement to acquire a 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block, effective January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS.

We were awarded Block WL4-00, which encompasses approximately 629,000 gross acres, in January 2017. We have a 50 percent operated interest in this block which includes the Salam-1 oil discovery.

We completed a 3-D seismic survey in Block SK 313 and Block WL4-00 in 2017. Further exploration drilling is expected to occur in 2018.

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Brunei

Exploration

We have a 6.25 percent working interest in the deepwater Block CA-2 PSC. Exploration has been ongoing since September 2011, with natural gas discovered at the Kelidang NE-1 and Keratau-1 wells in 2013 and at the Keratau SW-1 Well in 2015. Evaluation of the results is ongoing.

Qatar

	Interest	Operator	2017 Liquids MBD	2017 Natural Gas MMCFD	2017 Total MBOED
Average Daily Net Production					
QG3	30.0 %	Qatargas Operating Company Limited	21	369	83
Total Qatar			21	369	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 and Chile.

Colombia

Unconventional Exploration

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. Socialization and environmental permitting activities are expected to continue throughout 2018.

In July 2017, ConocoPhillips Colombia Ventures Ltd. and Canacol Energy Colombia S.A. executed an Additional Contract for the exploration and exploitation of unconventional reservoirs in an area identified as the VMM-2 Block. As a result, ConocoPhillips Colombia Ventures Ltd. and Canacol Energy Colombia S.A. also executed a joint operating agreement. We have an 80 percent operated working interest in the block which extends over approximately 58,000 net acres and is contiguous to the VMM-3 Block.

In 2017, we relinquished our 70 percent nonoperated interests in the deep rights in the Santa Isabel Block and terminated the exploration and production contract for the VMM27 Block, both in the Middle Magdalena Basin.

Chile
Exploration
We have a 49 percent interest in the Coiron Block located in the Magallanes Basin in southern Chile. In December 2017, two wells drilled in 2016, were expensed as dry holes.

Venezuela and Ecuador
For discussion of our contingencies in Venezuela and Ecuador, see Note 12—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, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, 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 United States, 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 natural gas liquids revenues are derived from production in the United States, 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 2—Variable Interest Entities (VIEs), 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 United Kingdom, 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 United States by MWCC.

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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 U.S. 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 fewer emissions, improve the efficiency of our company's 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 25 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, 2017. No difference exists between our estimated total proved reserves for year-end 2016 and year-end 2015, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2017.

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 1.7 trillion cubic feet of natural gas, including approximately 303 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 99 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2029. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves 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 proved undeveloped reserves.

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, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 4, 2017, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids production and reserves, and the fourth-largest U.S.-based oil and gas company in worldwide natural gas production and reserves in 2016. 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 2017, we held a total of 734 active patents in 47 countries worldwide, including 328 active U.S. patents. During 2017, we received 32 patents in the United States and 40 foreign patents. Our products and processes generated licensing revenues of $79 million in 2017. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $100 million, $116 million and $222 million in 2017, 2016 and 2015, respectively.

Health, Safety and Environment

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental 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 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 also have detailed processes in place to address 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 61 through 64 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2017 and those expected for 2018 and 2019.

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 U.S. Securities and Exchange Commission (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. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

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, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have experienced significant declines from their historic levels during 2013 and 2014, with excess of supply relative to global demand leading to global inventory builds. Total average annual prices in 2017 for Brent crude oil, WTI crude oil, Henry Hub natural gas and our realized natural gas liquids all decreased by at least 30 percent when compared with 2014 despite having improved by at least 18 percent when compared with 2016. Given volatility in commodity price drivers and the business environment, price trends may not continue or reverse themselves.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, natural gas liquids and LNG. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity and on the amount of dividends we elect to declare and pay on our common stock. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our 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, natural gas liquids and LNG prices could also require us to reduce our capital expenditures or impair the carrying value of our assets. In the past three years, we recognized several impairments, which are described in Note 8—Impairments and the "APLNG" section of Note 5—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 reserves we establish for future capital expenditures.
- 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 distributions to our stockholders; however, we bear all expenses incurred by our operations, and our funds generated by operations, after deducting these expenses, may not be sufficient to cover desired levels of distributions to our stockholders.

Additionally, our share repurchase program does not obligate us to acquire any specific number of shares. Any downward revision in our distribution or share repurchase program could have a material 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 stated 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, our growth could be impeded.

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. For example, due to the significant decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG in 2015, and the expectation that these prices could remain depressed, the major ratings agencies conducted a review of the oil and gas industry and downgraded our debt ratings and those of several companies operating in the industry in 2016. Any downgrade in our credit rating, 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 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.

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

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we 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 natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, 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.

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

The exploration and production of crude oil, bitumen, natural gas and natural gas liquids 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 natural gas liquids 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 natural gas liquids reserves could impair the quantity and value of those reserves.

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. 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. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

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. Likewise, future environmental laws and regulations, such as limitations on greenhouse gas emissions, may impact or limit our current business plans and reduce demand for our products.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and greenhouse gas 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 tight oil 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. 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.

Although our business operations are designed and operated 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 we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the Paris climate conference in December 2015. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Our operations and the demand for our products could be materially impacted by the development and adoption of these technologies.

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 tax and other legislation, executive order and commercial restrictions, including changes resulting from the implementation and interpretation of the Tax Cuts and Jobs Act, could reduce our operating profitability both in the United States 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. U.S. federal, state and local legislative and regulatory agencies' initiatives regarding the hydraulic fracturing process could result in operating restrictions or delays in the completion of our oil and gas wells.

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 have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future. Changes in domestic and international regulations may affect our ability 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 58 percent of our hydrocarbon production was derived from production outside the United States in 2017, and 45 percent of our proved reserves, as of December 31, 2017, was located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids or LNG pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. In particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty 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.

Changes in governmental regulations may impose price controls and limitations on production of crude oil, bitumen, natural gas and natural gas liquids.

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 natural gas liquids wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

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 acquisitions or joint ventures 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.

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.

We do not insure against all potential losses; therefore, we could be harmed by unexpected liabilities and increased costs.

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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, 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. Activities in deepwater areas 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 cybersecurity breaches. Although we have experienced occasional, actual or attempted breaches of our cybersecurity, none of these breaches has had a material effect on our business, operations or reputation. If our systems for protecting against cybersecurity risks prove to be insufficient, we could be adversely affected by having our business systems compromised, our proprietary information altered, lost or stolen, or our business operations disrupted. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

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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 2017, as well as matters previously reported in our 2016 Form 10-K and our first-, second- and third-quarter 2017 Form 10-Qs that were not resolved prior to the fourth quarter of 2017. 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 Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party's hazardous waste permit. The complaint seeks as relief remediation of area groundwater; compliance with the hazardous waste permit; enhanced pipeline and tank integrity measures; additional spill reporting; and fines and penalties exceeding $100,000.

In October 2016, after Phillips 66 received a Notice of Intent to Sue from the Sierra Club, Phillips 66 entered into a voluntary settlement with the Illinois Environmental Protection Agency for alleged violations of wastewater requirements at the Wood River Refinery. The settlement involves certain capital projects and payment of $125,000. After the settlement was filed with the Court for final approval, the Sierra Club sought and was granted approval to intervene in the case. The settlement and a first modification have been entered by the Court, but the Sierra Club still seeks to reopen and challenge the settlement.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Janet L. Carrig	Senior Vice President, Legal, General Counsel and Corporate Secretary	60
Ellen R. DeSanctis	Vice President, Investor Relations and Communications	61
Matt J. Fox	Executive Vice President, Strategy, Exploration and Technology	57
Alan J. Hirshberg	Executive Vice President, Production, Drilling and Projects	56
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	55
Andrew D. Lundquist	Senior Vice President, Government Affairs	57
James D. McMorran	Vice President, Human Resources, Real Estate and Facilities Services	60
Glenda M. Schwarz	Vice President and Controller	52
Don E. Wallette, Jr.	Executive Vice President, Finance, Commercial and Chief Financial Officer	59

**On February 15, 2018.*

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 15, 2018. Set forth below is information about the executive officers.

Janet L. Carrig was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007. On February 14, 2018, Ms. Carrig announced her decision to retire as Senior Vice President, Legal, General Counsel and Corporate Secretary. Ms. Carrig plans to remain in her current position until her successor is appointed.

Ellen R. DeSanctis was appointed Vice President, Investor Relations and Communications in May 2012. She was previously employed by Petrohawk Energy Corp. and served as Senior Vice President, Corporate Communications since 2010.

Matt J. Fox was appointed as Executive Vice President, Strategy, Exploration and Technology in April 2016. He previously served as the Executive Vice President, Exploration and Production, from 2012 to 2016. Prior to that, he was employed by Nexen, Inc. and served as Executive Vice President, International since 2010.

Alan J. Hirshberg was appointed Executive Vice President, Production, Drilling and Projects in April 2016. He previously served as Executive Vice President, Technology and Projects, from 2012 to 2016. Prior to that, he served as Senior Vice President, Planning and Strategy since 2010.

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.

James D. McMorran was appointed Vice President, Human Resources, Real Estate and Facilities Services in August 2015. Prior to that, he served as Manager, Compensation and Benefits, since 2004.

Glenda M. Schwarz was appointed Vice President and Controller in 2009.

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

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PART II

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

Quarterly Common Stock Prices and Cash Dividends Per Share

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

	Stock Price		
	High	Low	Dividends
2017			
First	**$ 51.68**	**43.26**	**0.265**
Second	**50.62**	**43.02**	**0.265**
Third	**50.83**	**42.27**	**0.265**
Fourth	**56.37**	**48.70**	**0.265**
2016			
First	$ 47.77	31.05	0.25
Second	49.35	38.19	0.25
Third	44.42	38.80	0.25
Fourth	53.17	40.37	0.25

Closing Stock Price at December 31, 2017	$ 54.89
Closing Stock Price at January 31, 2018	$ 58.46
Number of Stockholders of Record at January 31, 2018*	46,680

**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 4, 2016, we announced that our Board of Directors approved a reduction in the quarterly dividend to $0.25 per share, compared with the previous quarterly dividend of $0.74 per share.

On January 31, 2017, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.265 per share, compared with the previous quarterly dividend of $0.25 per share.

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.

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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, 2017	6,678,455	$ 49.94	6,678,455	$ 3,496
November 1-30, 2017	6,180,482	51.51	6,180,482	3,177
December 1-31, 2017	5,773,183	52.52	5,773,183	2,874
Total fourth-quarter 2017	18,632,120	$ 51.26	18,632,120	$ 2,874

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

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion, with the remaining balance to be repurchased in 2019. Acquisitions for the share repurchase program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. 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.

In addition to our previously announced share repurchase program above, we are currently planning to purchase up to an additional $1.5 billion of our common stock through 2020. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including Board authorization, market conditions and other factors. 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, 2012, to December 31, 2017. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index and our performance peer group consisting of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Anadarko, Apache, Marathon Oil Corporation, Devon and Occidental, weighted according to the respective peer's stock market capitalization at the beginning of each annual period. The comparison assumes $100 was invested on December 31, 2012, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer group and assumes that all dividends were reinvested.

LOGO

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2017	2016	2015	2014	2013
Sales and other operating revenues	**$ 29,106**	23,693	29,564	52,524	54,413
Income (loss) from continuing operations	**(793)**	(3,559)	(4,371)	5,807	8,037
Per common share					
Basic	**(0.70)**	(2.91)	(3.58)	4.63	6.47
Diluted	**(0.70)**	(2.91)	(3.58)	4.60	6.43
Income from discontinued operations	**-**	-	-	1,131	1,178
Net income (loss)	**(793)**	(3,559)	(4,371)	6,938	9,215
Net income (loss) attributable to ConocoPhillips	**(855)**	(3,615)	(4,428)	6,869	9,156
Per common share					
Basic	**(0.70)**	(2.91)	(3.58)	5.54	7.43
Diluted	**(0.70)**	(2.91)	(3.58)	5.51	7.38
Total assets	**73,362**	89,772	97,484	116,539	118,057
Long-term debt	**17,128**	26,186	23,453	22,383	21,073
Joint venture acquisition obligation—Cash dividends declared per common share	**1.06**	1.00	2.94	2.84	2.70

Net income (loss) and net income (loss) attributable to ConocoPhillips from 2013 to 2014 includes income from discontinued operations as a result of the sale of our interest in Kashagan, and the sales of our Algeria and Nigeria businesses. These factors impact the comparability of this 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 the world's largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our diverse portfolio primarily includes resource-rich North American tight oil and oil sands assets in Canada; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2017, we employed approximately 11,400 people worldwide and had total assets of $73 billion. Our common stock is listed on the New York Stock Exchange under the symbol "COP."

Overview

The global oil market is rebalancing. Crude oil prices improved in 2017, particularly during the latter half of the year; however, we believe prices are likely to remain cyclical in the future. In 2016, we updated our value proposition to position the company for long-term success, given our expectations. Our value proposition principles, namely to maintain financial strength, grow our distributions and pursue disciplined growth, remain essentially unchanged. However, we took steps to improve our competitiveness and resilience by establishing clear priorities for cash allocation.

In order, the cash allocation priorities are: invest capital at a level that maintains flat production volumes and pays our existing dividend; grow our existing dividend; reduce debt to a level we believe is sufficient to maintain a strong investment grade rating through price cycles; repurchase shares to provide value to our shareholders; and strategically invest capital to grow our cash from operations.

In 2017, we took significant actions that allowed us to make substantial progress on our stated priorities. We believe that our commitment to our value proposition, as evidenced by the results discussed below, position the company for success in an environment of price uncertainty and ongoing volatility.

Key Operating and Financial Summary

Significant items during 2017 included the following:

- Achieved full-year production excluding Libya of 1,356 thousand barrels of oil equivalent per day (MBOED); underlying production excluding the impact of closed and planned dispositions grew 19 percent on a production per debt-adjusted share basis and 3 percent overall.
- Cash provided by operating activities exceeded capital expenditures by $2.5 billion, and exceeded capital expenditures and dividends by $1.2 billion.
- Paid down $7.6 billion of balance sheet debt, ending the year with debt of $19.7 billion.
- Generated approximately $16 billion from asset dispositions.
- Announced year-end proved reserves of 5.0 billion barrels of oil equivalent (BOE).
- Repurchased $3 billion of shares; reduced ending share count by 5 percent year over year.
- Reached settlement on Ecuador arbitration for $337 million.

Operationally, we continue to focus on safely executing our capital program and remaining attentive to our costs. Production excluding Libya was 1,356 MBOED in 2017 compared with 1,567 MBOED in 2016. Our underlying production, which excludes the full-year impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, increased 32 MBOED, or 3 percent year over year. Underlying production on a per debt-adjusted share basis grew by 19 percent compared to 2016. Production per debt-adjusted share is calculated on an underlying production basis using ending period debt divided by ending share price plus ending shares outstanding. We believe production per debt-adjusted share is useful to investors as it provides a consistent view of production on a total equity basis by converting debt to equity and allows for comparisons across peer companies.

We accomplished several strategic milestones in 2017, including progressing our efforts to optimize our portfolio. Our asset dispositions are in line with our strategy, announced in November 2016, to focus on low cost-of-supply projects in our portfolio that strategically fit our development plans. We generated approximately $16 billion in total consideration from the disposition of certain noncore assets which were directed to our stated cash priorities and general corporate purposes. For additional information on our dispositions, see Note 4—Assets Held for Sale, Sold or Acquired in the Notes to Consolidated Financial Statements.

In 2017, we reduced debt by $7.6 billion to $19.7 billion at year-end and repurchased 64 million shares of our common stock totaling $3 billion. Consistent with our commitment to grow our distributions, in the first quarter of 2017, we increased our quarterly dividend by 6 percent to $0.265 per share. We are managing our business to optimize and deliver on our value propositions and cash priorities in a demanding business environment.

Business Environment

After elevated levels of volatility in 2016, global market fundamentals trended towards a firmer balance in 2017. Crude oil prices improved in 2017 as a result of slower growth in global oil production, strong global oil demand and lower global inventory levels.

The energy industry has periodically experienced this type of extreme volatility due to fluctuating supply-and-demand conditions. 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 disciplined financial and operational priorities that underpin our value proposition.

Priorities
The priorities we believe will drive our success through the price cycles include:

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

  - 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 2017, including asset disposition impacts, we reduced our production and operating expenses by 9 percent as compared to 2016.

  - Maintain capital 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. Given our view of greater price volatility, we have shifted our capital allocation to focus on shorter cycle time, low cost-of-supply, unconventional programs in our resource base. Our cash allocation priorities call for the investment of sufficient capital to maintain production and pay the existing dividend. Additional allocations of capital toward growth projects will be dependent on satisfaction of other financial priorities. We use a disciplined approach, focused on value maximization and cash flow expansion, to set our capital plans.

    In November 2017, we announced a 2018 capital budget of $5.5 billion, including $3.5 billion of sustaining capital and $2 billion in accretive, short-cycle unconventional programs, future major projects and exploration activities.

  - Optimize our portfolio. We continue to optimize our asset portfolio by focusing on low cost-of-supply assets which strategically fit our development plans. In 2017, we generated approximately $16 billion in total consideration from dispositions of certain noncore assets in our portfolio, including our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets; our interests in the San Juan Basin; and our interest in the Panhandle assets. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

- Maintain financial strength. We believe financial strength is critical in a cyclical business such as ours. In 2017, using proceeds from asset dispositions and cash flow from operations, we reduced our debt by $7.6 billion to $19.7 billion at year-end. On a longer-term basis, in November 2017, we announced our plan to reduce debt to $15 billion by year-end 2019, a significant acceleration from the previously stated expectation of $20 billion in the same timeframe. We expect to retire outstanding debt as it matures and exercise flexibility in paying down our other debt instruments.

- Return capital to shareholders. In 2017, we paid dividends on our common stock of $1.3 billion and repurchased $3 billion of our common stock. We believe in delivering value to our shareholders through the price cycles. As a result, we set a priority to increase our dividend rate annually and purchase up to approximately $3 billion of our common stock evenly from 2018 through 2019.

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. Additionally, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion.

In addition to our previously announced share repurchase program above, we are currently planning to purchase up to an additional $1.5 billion of our common stock through 2020. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including Board authorization, market conditions and other factors. See Risk Factors "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

- 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. Our sustainability efforts in 2017 focused on implementing our action plans for climate change, biodiversity, water and human rights, as well as revamping public reporting to be more informative, searchable and responsive to common questions. To demonstrate our commitment to sustainability and environmental stewardship, on November 2017, we announced our intention to target a 5 to 15 percent reduction in our greenhouse gas emission intensity by 2030. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved Health, Safety and Environment and operational performance.

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

  - Successful exploration, exploitation and development of new and existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.

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. Asset dispositions in 2017 reduced our reported year-end proved reserves, but were partly offset by increased commodity prices. In 2017, our reserve replacement, which included a reduction of 1.9 billion BOE from dispositions, was negative 168 percent. Our organic reserve replacement, which excludes the impact of sales and purchases, was 200 percent in 2017. In the five years ended December 31, 2017, our reserve replacement was negative 24 percent, reflecting the impact of asset dispositions and lower prices.

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. Additionally, as we continue cash conservation efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves.

- 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 we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations. Such innovations enable us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

- Develop and retain a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills 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.

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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 Organization of Petroleum Exporting Countries (OPEC), environmental laws, tax regulations, governmental policies and weather-related disruptions. The following graph depicts the average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:

LOGO

Brent crude oil prices averaged $61.39 per barrel in the fourth quarter of 2017, an increase of 24 percent compared with $49.46 per barrel in the fourth quarter of 2016. Similarly, WTI crude oil prices increased 13 percent from $49.18 per barrel in the fourth quarter of 2016 to $55.35 per barrel in the same period of 2017. Global oil prices began to improve at the end of 2016 and continued trending upward in response to stronger global demand and slower production growth.

Henry Hub natural gas prices averaged $2.93 per million British thermal units (MMBTU) in the fourth quarter of 2017, a decrease of 2 percent compared with $2.98 per MMBTU in the fourth quarter of 2016. However, on an annual basis, Henry Hub natural gas prices improved 26 percent from $2.46 per MMBTU in 2016, to $3.11 per MMBTU in 2017. The price improvement was as a result of growth in domestic demand, increased exports and lower U.S. inventories.

Our realized natural gas liquids prices averaged $32.79 per barrel in the fourth quarter of 2017, an increase of 50 percent compared with $21.82 per barrel in the same quarter of 2016.

Improving global crude oil prices resulted in the Western Canada Select benchmark price experiencing a 33 percent increase, from $29.36 per barrel in 2016 to $38.92 per barrel in 2017. The WCS benchmark price improvement, coupled with changes in costs per barrel resulting from the disposition of our interest in the FCCL Partnership, caused our realized bitumen price to increase relative to 2016. Our realized bitumen price was $22.66 per barrel in 2017, an increase of 48 percent compared with $15.27 per barrel in the same period of 2016.

Our worldwide annual average realized price was $46.10 per barrel of oil equivalent (BOE) in the fourth quarter of 2017, an increase of 40 percent compared with $32.93 per BOE in the fourth quarter of 2016. Similarly, our worldwide annual average realized price was $39.19 per BOE in 2017, an increase of 38 percent compared with $28.35 per BOE in 2016, reflecting higher average realized prices across all commodities.

North America's energy landscape has been transformed from resource scarcity to an abundance of supply. In recent years, the use of hydraulic fracturing and horizontal drilling in tight oil formations has led to increased industry actual and forecasted crude oil and natural gas production in the United States. 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 tight oil plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; delay of plans to develop areas such as unconventional fields or Alaska North Slope natural gas fields; and underutilization of LNG regasification facilities. Should one or more of these events occur, our revenues would be reduced and additional asset impairments might be possible.

- Impairments. As mentioned earlier, we participate in a capital-intensive industry. At times, our properties, plants and equipment 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. In 2017, we recorded before-tax impairments of $6,601 million for proved properties and $136 million for unproved properties. 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. For additional information on our impairments in 2017, 2016 and 2015, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.

- Effective tax rate. Our operations are located 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. Recent changes in the U.S. corporate income tax law, further discussed below, additionally impacted our effective tax rate in 2017.

- 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 United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our assets in Venezuela were expropriated in 2007. Our production operations in Libya and related oil exports were suspended or significantly curtailed from July 2013 to October 2016 due to the closure of the Es Sider crude oil export terminal, and they were also suspended in 2011 during Libya's period of civil unrest. In 2016, the United Kingdom government enacted tax legislation which reduced our U.K. corporate tax rate by 10 percent.

On December 22, 2017, the Tax Cuts and Jobs Act ("Tax Legislation") was enacted, significantly revising the U.S. corporate income tax law by, among other things, lowering the corporate income tax rate from 35 percent to 21 percent, implementing a territorial tax system and imposing a one-time deemed repatriation tax on untaxed accumulated foreign earnings. We recognized a provisional, noncash tax benefit of $852 million, which is included as a component of our 2017 income tax expense, primarily related to the revaluation of deferred taxes at the lower 21 percent federal statutory rate. We did not incur nor expect to incur a tax cost related to the one-time repatriation of accumulated foreign earnings. While we anticipate the Tax Legislation will provide a positive impact to our U.S. operations in the future primarily because of the reduced U.S. federal statutory rate, we do not expect to realize cash tax benefits from the Tax Legislation until we move into a U.S. tax paying position. The ultimate impact of the Tax Legislation may differ from our current expectations, due to, among other things, changes in interpretations and assumptions the company has made or additional regulatory or accounting guidance that may be issued with respect to the Tax Legislation. For additional information, see Note 18—Income Taxes, in the Notes to Consolidated Financial Statements.

Our management carefully considers the fiscal and regulatory environment when evaluating projects or determining the levels and locations of our activity.

Outlook

Full-year 2018 production is expected to be 1,195 to 1,235 MBOED. This results in approximately 5 percent growth compared with full-year 2017 underlying production, which excludes the impact of closed and planned dispositions of 191 MBOED. First-quarter 2018 production is expected to be 1,180 to 1,220 MBOED. Production guidance for 2018 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 received.

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

Consolidated Results

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

	Millions of Dollars		
Years Ended December 31	**2017**	2016	2015
Alaska	$ **1,466**	319	4
Lower 48	**(2,371)**	(2,257)	(1,932)
Canada	**2,564**	(935)	(1,044)
Europe and North Africa	**553**	394	409
Asia Pacific and Middle East	**(1,098)**	209	(463)
Other International	**167**	(16)	(593)
Corporate and Other	**(2,136)**	(1,329)	(809)
Net loss attributable to ConocoPhillips	$ **(855)**	(3,615)	(4,428)

2017 vs. 2016

Loss attributable to ConocoPhillips decreased $2,760 million in 2017. The decrease was mainly due to:

- Higher commodity prices.
- Lower depreciation, depletion and amortization (DD&A) expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Higher gains on dispositions, primarily due to a $1.6 billion after-tax gain in 2017 on the sale of certain Canadian assets.
- Recognition of deferred tax benefits totaling $996 million, primarily related to the disposition of certain Canadian assets.
- Recognition of deferred tax benefits totaling $852 million related to the Tax Legislation enacted on December 22, 2017.
- Improved equity earnings, mainly due to higher realized prices, lower DD&A from asset disposition impacts, and the absence of a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to the U.S. dollar. These increases were partly offset by lower volumes from the disposition of our interest in the FCCL Partnership.
- Lower exploration expenses mainly due to reduced leasehold impairment expense, dry hole costs and other exploration expenses.
- A $337 million award from an arbitration settlement with The Republic of Ecuador.
- Lower production and operating expenses, primarily due to asset disposition impacts.
- Lower net interest expense, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and reduced debt.

The reduction in loss was partly offset by:

- Higher proved property and equity investment impairments, including a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the ongoing marketing of the Barnett, as well as a $2.4 billion before- and after-tax impairment of our equity investment in APLNG.
- Lower volumes primarily due to asset dispositions in our Lower 48, Asia Pacific and Middle East, and Canada segments, as well as normal field decline.
- A $238 million after-tax charge associated with our early retirements of debt in 2017.

2016 vs. 2015

Loss attributable to ConocoPhillips decreased $813 million in 2016. The decrease was mainly due to:

- Lower exploration expenses. Exploration expenses decreased mainly due to reduced leasehold impairment expense and dry hole costs.
- Lower proved property and equity investment impairments, including the absence of a $1.5 billion before- and after-tax impairment of our equity investment in APLNG in 2015.
- Lower production and operating expenses.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- The absence of a $129 million deferred tax charge from increased corporate tax rates in Canada in 2015.

The decrease in loss was partly offset by:

- Lower commodity prices.
- The absence of a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in 2015.
- Lower crude oil, natural gas liquids, and gas sales volumes.
- Lower equity earnings, primarily driven by increased DD&A expense, as well as a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to U.S. dollar.
- Higher interest and debt expense.
- Lower gain on dispositions, mainly due to the absence of a $368 million after-tax gain on the disposition of certain properties in our Lower 48 segment.

Income Statement Analysis

2017 vs. 2016

Sales and other operating revenues increased 23 percent in 2017, mainly due to higher realized prices across all commodities, partly offset by lower sales volumes, primarily in our Lower 48, Asia Pacific and Middle East, and Canada segments as a result of dispositions.

Equity in earnings of affiliates increased $720 million in 2017. The increase in equity earnings was primarily due to higher realized commodity prices at QG3, APLNG and FCCL; the absence of a 2016 deferred tax charge of $174 million resulting from a tax functional currency change; and reduced costs mainly from the disposition of our interest in the FCCL Partnership. The increase in earnings was partly offset by lower volumes as a result of our FCCL disposition.

Gain on dispositions increased 505 percent in 2017. The increase was primarily due to a before-tax gain of $2.1 billion on the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets. For additional information on gains on dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

Other income increased 107 percent in 2017, mainly due to a $337 million before- and after-tax International Centre for Settlement of Investment Disputes (ICSID) arbitration award from The Republic of Ecuador. The increase was partly offset by the absence of a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust and a $76 million before-tax damage claim settlement, both in our Lower 48 segment in 2016.

Purchased commodities increased 25 percent in 2017, mainly due to higher commodity prices and increased activity.

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Selling, general and administrative (SG&A) expenses decreased 22 percent in 2017, primarily due to reduced restructuring expenses, lower headcount and reduced activity.

Exploration expenses decreased 51 percent in 2017, primarily as a result of lower leasehold impairment expense, dry hole costs and other exploration expenses.

Leasehold impairment expense was reduced mainly due to the absence of 2016 before-tax charges of $203 million for our Gibson and Tiber leaseholds. The expense was further reduced by the absence of before-tax charges of $95 million for our Melmar leasehold and $79 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by a before-tax charge of $51 million for Shenandoah in deepwater Gulf of Mexico and a before-tax charge of $38 million for certain mineral assets in our Lower 48 segment, both in 2017.

Dry hole costs were reduced primarily due to the absence of 2016 before-tax charges in deepwater Gulf of Mexico of $249 million for our Gibson and Tiber wells, and $128 million for our Melmar well. The absence of a $256 million before-tax charge in 2016 for two dry holes in Nova Scotia further reduced costs. The reduction in dry hole costs was partly offset by 2017 before-tax charges of $288 million for multiple wells in Shenandoah, including wells previously suspended, and $63 million for several wells in the Powder River Basin.

Other exploration expenses were reduced mainly due to the absence of a $146 million before-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract, as well as lower rig stacking costs in Angola. The decrease in expense was partly offset by a $43 million net before-tax charge in 2017 for the settlement of our drilling rig contract in Angola.

For additional information on leasehold impairments and other exploration expenses, see Note 7—Suspended Wells and Other Exploration Expenses, and Note 8—Impairments, in the Notes to Consolidated Financial Statements.

DD&A decreased 24 percent in 2017, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts in our Canada and Lower 48 segments.

Impairments increased $6,462 million in 2017. For additional information, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.

Interest and debt expense decreased 12 percent in 2017, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest on debt.

Other expense included before-tax charges of $302 million in 2017 for premiums on early debt retirements.

See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax benefit and effective tax rate.

2016 vs. 2015

Sales and other operating revenues decreased 20 percent in 2016, mainly as a result of lower prices across all commodities. Additionally, sales and other operating revenues decreased due to lower natural gas, crude oil and natural gas liquids sales volumes, mainly from dispositions and field decline, partly offset by increased bitumen sales volumes.

Equity in earnings of affiliates decreased 92 percent in 2016. The decrease was primarily due to lower commodity prices, increased DD&A mainly from Trains 1 and 2 being placed in service at APLNG, and a 2016 deferred tax charge of $174 million resulting from a tax functional currency change. The decrease in earnings was partly offset by higher sales volumes at APLNG and FCCL Partnership, as well as lower production taxes at QG3.

Gain on dispositions decreased 39 percent in 2016. The decrease resulted from the absence of a $583 million before-tax gain in 2015 from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas, as well as a $26 million before-tax loss on the sale of our interest in the Block B PSC in Indonesia in 2016. The decrease was partly offset by the absence of a $149 million before-tax loss on the disposition of noncore assets in western Canada in the fourth quarter of 2015; and gains on the 2016 dispositions of ConocoPhillips Senegal B.V., the entity that held our interests in three exploration blocks offshore Senegal, the Alaska Beluga River Unit natural gas field, and noncore assets in the Lower 48. For additional information on gains on dispositions, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

Other income increased 104 percent in 2016, mainly due to a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust in the fourth quarter of 2016. Other income was further increased $76 million before-tax for a damage claim settlement in our Lower 48 segment.

Purchased commodities decreased 20 percent in 2016, mainly due to lower natural gas prices.

Production and operating expenses decreased 19 percent in 2016, mainly due to lower operating expense activity, reduced headcount and dispositions of noncore assets, as well as favorable foreign currency impacts.

SG&A expenses decreased 24 percent in 2016, primarily due to reduced restructuring expenses, lower headcount and reduced activity. The decrease was partly offset by increases from market impacts on certain compensation programs.

Exploration expenses decreased 54 percent in 2016, primarily as a result of lower leasehold impairment expense, dry hole costs, and other exploration expenses.

Leasehold impairment expense was reduced, mainly due to the absence of 2015 before-tax charges of $575 million for our Chukchi Sea leasehold and capitalized interest; $493 million for Angola Blocks 36 and 37; and $447 million for certain Gulf of Mexico leases, partly offset by 2016 impairments of our Melmar, Gibson, Tiber and other Gulf of Mexico leaseholds.

Dry hole costs were reduced due to the absence of before-tax charges of $1,141 million in 2015, mainly from wells in deepwater Gulf of Mexico, Horn River and Northwest Territories in Canada, Angola Blocks 36 and 37, and Malaysia. The reduction in costs was partly offset by before-tax charges in 2016, including $434 million from several wells in deepwater Gulf of Mexico and $256 million for two wells in Nova Scotia.

Other exploration expenses were reduced mainly due to the absence of a $335 million before-tax charge in 2015 related to the termination of our Ensco Gulf of Mexico deepwater drillship contract, partly offset by before-tax rig cancellation charges and third-party costs of $146 million for our final Gulf of Mexico deepwater drillship contract in 2016.

For additional information on leasehold impairments and other exploration expenses, see Note 7—Suspended Wells and Other Exploration Expenses, and Note 8—Impairments, in the Notes to Consolidated Financial Statements.

Impairments decreased 94 percent in 2016. For additional information, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 18 percent in 2016, primarily as a result of lower production taxes, mainly in our Alaska and Lower 48 segments, given reduced commodity prices and the absence of the impact of a transportation cost ruling by the Federal Energy Regulatory Commission in the fourth quarter of 2015 in Alaska. Taxes other than income taxes were additionally decreased due to lower property taxes in 2016 in our Alaska and Lower 48 segments.

Interest and debt expense increased 35 percent in 2016, primarily due to lower capitalized interest on projects and increased debt.

See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax benefit and effective tax rate.

Summary Operating Statistics

	2017	2016	2015
Average Net Production			
Crude oil (MBD)*	**599**	598	605
Natural gas liquids (MBD)	**111**	145	156
Bitumen (MBD)	**122**	183	151
Natural gas (MMCFD)**	**3,270**	3,857	4,060
Total Production (MBOED)***	**1,377**	1,569	1,589
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)	**$ 51.96**	40.86	48.26
Natural gas liquids (per barrel)	**25.22**	16.68	17.79
Bitumen (per barrel)	**22.66**	15.27	18.72
Natural gas (per thousand cubic feet)	**4.07**	3.00	3.96
	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical, lease rental, and other	**$ 372**	731	1,127
Leasehold impairment	**136**	466	1,924
Dry holes	**430**	718	1,141
	$ 938	1,915	4,192

**Thousands of barrels per day.*
***Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*
****Thousands of barrels of oil equivalent per day.*

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2017, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Total production, including Libya, of 1,377 MBOED decreased 12 percent in 2017 compared with 2016. The decrease in total average production primarily resulted from noncore asset dispositions, including our Canada and San Juan transactions in 2017 and the sale of our interest in the Block B production sharing contract (PSC) in Indonesia in 2016, and normal field decline. The decrease in production was partly offset by production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont in Canada; and APLNG in Australia. Improved drilling and well performance in Alaska, Norway and China also partly offset the decrease in production. Excluding Libya, our 2017 production was 1,356 MBOED. Adjusted for the impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, our underlying production increased 32 MBOED, or 3 percent, compared with 2016.

In 2016, total production, including Libya, of 1,569 MBOED decreased 1 percent compared with 2015. The decrease in total average production primarily resulted from normal field decline and the loss of 72 MBOED mainly attributable to the 2015 dispositions of several noncore assets in the Lower 48, western Canada and the sale of our interest in the Polar Lights Company in Russia. The decrease in production was partly offset by additional production from major developments, including tight oil plays in the Lower 48; APLNG in Australia; the Western North Slope in Alaska; the Kebabangan gas field in Malaysia; and the Greater Ekofisk Area in Norway. Improved drilling and well performance in Canada, Norway, the Lower 48, and China, as well as lower unplanned downtime in the Lower 48 also partly offset the decrease in production. Assets sold in 2016 produced 27 MBOED and 36 MBOED in 2016 and 2015, respectively.

Alaska

	2017	2016	2015
Net Income Attributable to ConocoPhillips (millions of dollars)	**$ 1,466**	319	4
Average Net Production			
Crude oil (MBD)	**167**	163	158
Natural gas liquids (MBD)	**14**	12	13
Natural gas (MMCFD)	**7**	25	42
Total Production (MBOED)	**182**	179	178
Average Sales Prices			
Crude oil (per barrel)	**$ 53.33**	41.93	51.61
Natural gas (per thousand cubic feet)	**2.72**	5.22	4.33

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2017, Alaska contributed 22 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

2017 vs. 2016

Alaska reported earnings of $1,466 million in 2017, compared with earnings of $319 million in 2016. The increase in earnings was mainly due to an $892 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the newly enacted Tax Legislation. Earnings were additionally improved due to higher crude oil prices in 2017. The earnings increase was partly offset by a $110 million after-tax impairment charge for the associated properties, plants and equipment of our small interest in the Point Thomson unit.

Average production increased 2 percent in 2017 compared with 2016, as the impact of normal field decline was more than offset by well performance in the Western North Slope, Greater Prudhoe and Greater Kuparuk areas and lower unplanned downtime.

2016 vs. 2015

Alaska reported earnings of $319 million in 2016, compared with earnings of $4 million in 2015. The increase in earnings was mainly due to:

- Lower exploration expenses, primarily due to the absence of the 2015 impairment charge for our Chukchi Sea leasehold and capitalized interest. For additional information on our impairments, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.
- Reduced production and operating expense, mainly from lower maintenance costs and general and administrative expenses.
- Enhanced oil recovery tax credits.

- Higher crude oil sales volumes, partly offset by the absence of LNG sales volumes.
- A $57 million after-tax impact for the recognition of state deferred tax assets.
- A $36 million after-tax gain on the sale of our interest in the Alaska Beluga River Unit natural gas field.

The increase in earnings was partly offset by lower crude oil prices and higher DD&A expense, mainly due to capital additions.

Average production increased 1 percent in 2016 compared with 2015, primarily due to new production from the Alpine CD5 drill site and strong well performance in the Greater Prudhoe Area. The production increase was partly offset by normal field decline.

Acquisition
In January 2018, we entered into an agreement to acquire certain oil and gas assets in Alaska for $400 million, subject to customary adjustments. The acquisition is subject to regulatory approval. We will have a 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery.

Lower 48

	2017	2016	2015
Net Loss Attributable to ConocoPhillips (millions of dollars)	**$ (2,371)**	(2,257)	(1,932)
Average Net Production			
Crude oil (MBD)	**180**	195	206
Natural gas liquids (MBD)	**69**	88	94
Natural gas (MMCFD)	**898**	1,219	1,472
Total Production (MBOED)	**399**	486	545
Average Sales Prices			
Crude oil (per barrel)	**$ 47.36**	37.49	42.62
Natural gas liquids (per barrel)	**22.20**	14.34	14.01
Natural gas (per thousand cubic feet)	**2.73**	2.20	2.43

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and exploration activities in the Gulf of Mexico. During 2017, the Lower 48 contributed 30 percent of our worldwide liquids production and 27 percent of our natural gas production.

2017 vs. 2016

Lower 48 reported a loss of $2,371 million after-tax in 2017, compared with a loss of $2,257 million after-tax in 2016. The increase in loss was primarily due to proved property impairments in 2017, totaling $2.5 billion after-tax, for our interests in the San Juan Basin and the Barnett which were written down to fair value less costs to sell. Lower natural gas, crude oil and natural gas liquids sales volumes from asset dispositions and normal field decline further increased losses during the year.

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The increase in losses was partly offset by:

- Lower DD&A expense, mainly resulting from a lower unit-of-production rate from reserve revisions, disposition impacts and lower volumes.
- A $689 million tax benefit, primarily related to the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the newly enacted Tax Legislation.
- Higher realized crude oil, natural gas liquids and natural gas prices.
- Lower exploration expenses mainly due to:

  - Lower leasehold impairment expense, primarily the absence of 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds; $62 million for our Melmar leasehold and $52 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by an after-tax charge of $33 million for Shenandoah in deepwater Gulf of Mexico and an after-tax charge of $24 million for certain mineral assets, both in 2017.
  - Lower other exploration expenses, mainly due to the absence of a $95 million after-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract.
  - Lower dry hole costs primarily due to the absence of 2016 after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells, and $83 million for our Melmar well, partly offset by 2017 after-tax charges of $187 million for multiple wells in Shenandoah and $41 million for several wells in the Powder River Basin.

In 2017, our average realized crude oil price of $47.36 per barrel was 7 percent less than WTI of $50.90 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast and Bakken.

Total average production decreased 18 percent in 2017 compared with 2016. The decrease was mainly attributable to normal field decline and the disposition of our interests in the San Juan Basin, partly offset by new production, primarily from Eagle Ford and Bakken.

Asset Disposition
On July 31, 2017, we completed the sale of our interests in the San Juan Basin for total proceeds comprised of $2.5 billion in cash after customary adjustments and 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 million British thermal units.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

For additional information on our asset sales in the Lower 48, see Note 4—Assets Held for Sale, Sold or Acquired, in the Notes to Consolidated Financial Statements.

2016 vs. 2015

Lower 48 reported a loss of $2,257 million after-tax in 2016, compared with a loss of $1,932 million after-tax in 2015. The increase in losses was primarily due to:

- The absence of a $368 million after-tax gain on the disposition of certain properties in South Texas, East Texas and North Louisiana.
- Lower crude oil and natural gas prices.
- Lower sales volumes across all commodities due to dispositions and field decline.
- Higher proved property impairments, including a $49 million after-tax impairment associated with changes to development plans for Eagle Ford infrastructure.

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The increase in losses was partly offset by:

- Lower production and operating expenses, mainly due to reduced activity and cost efficiencies.
- Lower exploration expenses, mainly due to:
  - Reduced other exploration costs, mainly due to the absence of a $216 million after-tax charge related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in 2015, partly offset by 2016 rig cancellation and related third party costs of $95 million after-tax for our final Gulf of Mexico deepwater drillship contract.
  - Lower general and administrative, and geological and geophysical expenses.
  - Lower leasehold impairment expense, including the absence of 2015 after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect. The decrease in leasehold impairment was partly offset by 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds and $62 million for the Melmar Prospect, all in the Gulf of Mexico.
  - Lower exploration expenses were partly offset by slightly increased dry hole costs in 2016, including after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells and $83 million associated with our Melmar well. Dry hole costs in 2016 were partly offset by the absence of a $111 million after-tax charge in 2015 associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.
- An $88 million gain associated with our receipt of Greater Northern Iron Ore Properties Trust assets in the fourth quarter of 2016.
- A $48 million after-tax benefit from a damage claim settlement.
- A $38 million after-tax gain from the disposition of noncore assets and lease exchanges.
- Lower DD&A, mainly due to 2016 reserve additions and reduced volumes, partly offset by price-related reserve revisions.

Total average production decreased 11 percent in 2016 compared with 2015. The decrease was mainly attributable to normal field decline and the 2015 disposition of noncore properties in East Texas and North Louisiana, as well as South Texas. The reduction was partly offset by new production and well performance, primarily from Eagle Ford, Bakken and the Permian Basin, as well as lower unplanned downtime.

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Canada

	2017	2016	2015
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ 2,564**	(935)	(1,044)
Average Net Production			
Crude oil (MBD)	**3**	7	12
Natural gas liquids (MBD)	**9**	23	26
Bitumen (MBD)			
Consolidated operations	**59**	35	13
Equity affiliates	**63**	148	138
Total bitumen	**122**	183	151
Natural gas (MMCFD)	**187**	524	715
Total Production (MBOED)	**165**	300	308
Average Sales Prices			
Crude oil (per barrel)	**$ 43.69**	35.25	39.52
Natural gas liquids (per barrel)	**21.51**	14.82	17.02
Bitumen (dollars per barrel)			
Consolidated operations	**21.43**	12.91	20.13
Equity affiliates	**23.83**	15.80	18.58
Total bitumen	**22.66**	15.27	18.72
Natural gas (per thousand cubic feet)	**1.93**	1.49	1.91

Our Canadian operations mainly consist of an oil sands development in the Athabasca region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2017, Canada contributed 16 percent of our worldwide liquids production and 6 percent of our worldwide natural gas production.

2017 vs. 2016

Canada operations reported earnings of $2,564 million in 2017, an increase of $3,499 million compared with 2016. The earnings increase was mainly due to an after-tax gain of $1.6 billion on the sale of certain Canadian assets, further discussed below, as well as the recognition of $996 million in deferred tax benefits related to the capital gains component of our disposition and the recognition of previously unrealizable Canadian tax basis.

In addition to the items discussed above, earnings were further increased due to:

- Lower DD&A, mainly from disposition impacts.
- Lower dry hole costs, mainly due to the absence of 2016 combined after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.
- Higher realized prices across all commodities.
- A $114 million tax benefit related to our prior decision to exit Nova Scotia deepwater exploration.
- Lower production and operating expenses.
- Improved equity earnings, as improved prices and reduced DD&A more than offset the volume loss from our Canada disposition.

The earnings increase was partly offset by additional volume reductions from the disposition of our western Canada gas assets.

Total average production decreased 45 percent in 2017 compared with 2016. The production decrease was primarily due to the Canada disposition, partly offset by production ramp-up at Surmont.

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 Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel. See Note 4—Assets Held for Sale, Sold or Acquired and Note 6—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, for additional information regarding our Canada disposition.

2016 vs. 2015

Canada operations reported a loss of $935 million in 2016, a decrease in loss of $109 million compared with 2015. The decrease in loss was primarily due to:

- The absence of a $136 million impact of a 2 percent increase in Alberta corporate tax rates on deferred taxes in 2015.
- Lower production and operating expenses, mainly due to reduced headcount and the disposition of noncore assets in western Canada.
- Lower exploration expenses, mainly due to:
  - Reduced leasehold impairment expense, including the absence of an impairment charge for undeveloped leasehold in the Duvernay, Thornbury, Saleski and Crow Lake areas. The reduction in leasehold impairment expense was partly offset by a $23 million after-tax charge in the fourth quarter of 2016 primarily due to decisions to discontinue further testing on undeveloped leaseholds.
  - Lower general and administrative, and geological and geophysical expenses.
  - Lower dry hole costs, mainly due to the absence of 2015 charges associated with our Horn River, Northwest Territories, Thornbury and Saleski properties, partly offset by dry hole costs in 2016, including total after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.
- Higher gains on dispositions, including the absence of a $103 million net after-tax loss on the disposition of noncore assets in western Canada in 2015.

The decrease in loss was partly offset by lower commodity prices; higher DD&A expense, mainly from price-related reserve revisions; and a $42 million after-tax impairment charge related to certain developed properties in central Alberta, which were classified as held for sale, being written down to fair value less costs to sell.

Total average production decreased 3 percent in 2016 compared with 2015, while bitumen production increased 21 percent over the same periods. The decrease in total production was mainly attributable to the disposition of noncore assets in western Canada and normal field decline. The production decrease was partly offset by strong well performance in western Canada, Surmont and FCCL.

Europe and North Africa

	2017	2016	2015
Net Income Attributable to ConocoPhillips (millions of dollars)	**$ 553**	394	409
Average Net Production			
Crude oil (MBD)	**142**	122	120
Natural gas liquids (MBD)	**8**	7	7
Natural gas (MMCFD)	**484**	460	476
Total Production (MBOED)	**230**	205	207
Average Sales Prices			
Crude oil (dollars per barrel)	**$ 54.21**	43.66	52.75
Natural gas liquids (per barrel)	**34.07**	22.62	27.56
Natural gas (per thousand cubic feet)	**5.70**	4.71	7.14

The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea and Libya. In 2017, our Europe and North Africa operations contributed 18 percent of our worldwide liquids production and 15 percent of our natural gas production.

2017 vs. 2016

Earnings for Europe and North Africa operations of $553 million increased 40 percent in 2017. The increase in earnings was primarily due to higher realized crude oil, natural gas and natural gas liquids prices. Earnings were additionally improved by lower DD&A, mainly due to reserve revisions; a $60 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the newly enacted Tax Legislation; and a $41 million tax benefit in Norway.

The increase in earnings was partly offset by the absence of a 2016 net deferred tax benefit of $161 million resulting from a change in the U.K. tax rate and a lower credit to impairment in 2017, compared to 2016, reflecting the annual updates to asset retirement obligations (ARO) on fields at or nearing the end of life which were impaired in prior years. The earnings improvement was further reduced by a net deferred tax charge of $65 million in the U.K. resulting from updated assumptions regarding applicable tax rates.

Average production increased 12 percent in 2017, compared with 2016. The increase was mainly due to the resumption and ramp-up of production in Libya; improved drilling and well performance in Norway; new production from the Greater Britannia Area and Norway; and higher Norway gas offtake, partly offset by normal field decline.

2016 vs. 2015

Earnings for Europe and North Africa operations of $394 million decreased 4 percent in 2016. The decrease in earnings was primarily due to the absence of a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015; lower crude oil and natural gas prices; lower sales volumes; and the absence of a 2015 after-tax gain of $49 million on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

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The decrease in earnings was partly offset by:

- Lower property impairments, including the absence of 2015 after-tax charges of $317 million in the U.K. due to lower crude oil and natural gas prices, and a $180 million credit to impairment in 2016 due to decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years. The reduction in property impairments was partly offset by a $59 million after-tax charge associated with our Calder Field and Rivers terminal in the U.K. For additional information on our impairments, see Note 8—Impairments, in the Notes to Consolidated Financial Statements.
- Lower DD&A expense in the U.K. driven by reduced rate, as a result of completed depreciation on the Brodgar H3 tie-back well in 2015, and lower volumes.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- Reduced operating expenses across the segment.

Average production decreased 1 percent in 2016, compared with 2015. The decrease in production was mainly due to normal field decline, partly offset by improved drilling and well performance in Norway and new production from the Greater Ekofisk and Greater Britannia areas. Libya production remained largely shut in, as the Es Sider crude oil export terminal closure continued throughout the third quarter of 2016. Production resumed in Libya in October 2016.

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Asia Pacific and Middle East

	2017	2016	2015
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ (1,098)**	209	(463)
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**93**	97	91
Equity affiliates	**14**	14	14
Total crude oil	**107**	111	105
Natural gas liquids (MBD)			
Consolidated operations	**4**	7	9
Equity affiliates	**7**	8	7
Total natural gas liquids	**11**	15	16
Natural gas (MMCFD)			
Consolidated operations	**687**	730	717
Equity affiliates	**1,007**	899	638
Total natural gas	**1,694**	1,629	1,355
Total Production (MBOED)	**401**	399	347
Average Sales Prices			
Crude oil (dollars per barrel)			
Consolidated operations	**$ 54.38**	42.23	49.70
Equity affiliates	**54.76**	44.11	53.12
Total crude oil	**54.43**	42.47	50.16
Natural gas liquids (dollars per barrel)			
Consolidated operations	**41.37**	29.00	37.78
Equity affiliates	**38.74**	31.13	35.79
Total natural gas liquids	**39.75**	30.11	36.88
Natural gas (dollars per thousand cubic feet)			
Consolidated operations	**4.98**	4.31	6.23
Equity affiliates	**4.27**	2.97	4.83
Total natural gas	**4.55**	3.57	5.58

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. During 2017, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 52 percent of our natural gas production.

2017 vs. 2016

Asia Pacific and Middle East reported a loss of $1,098 million in 2017, compared with earnings of $209 million in 2016. The increase in loss was mainly due to a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in 2017. For additional information on our APLNG impairment, see the “APLNG” section of Note 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. Additionally, lower sales volumes in Indonesia, Australia and China further increased losses.

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The increase in losses was partly offset by higher equity earnings, mainly as a result of higher commodity prices, increased sales volumes at APLNG and the absence of a 2016 deferred tax charge of $174 million resulting from the change of our APLNG tax functional currency. Higher realized crude oil and natural gas prices on non-equity volumes further reduced the loss.

Average production was essentially flat in 2017.

2016 vs. 2015

Asia Pacific and Middle East reported earnings of $209 million in 2016, compared with a loss of $463 million in 2015. The earnings increase was mainly due to:

- The absence of a $1,502 million before- and after-tax charge for the impairment of our APLNG investment in 2015. For additional information on our APLNG impairment, see the "APLNG" section of Note 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.
- Higher LNG sales volumes.
- Lower production taxes.
- Reduced feedstock costs at Darwin LNG.
- Lower operating expenses, mainly due to lower general and administrative spend, maintenance costs and transportation expenses across the segment.
- Lower exploration expenses, mainly due to lower dry hole costs, as well as the absence of a $41 million after-tax charge in 2015 for the impairment of our relinquished Palangkaraya PSC, and reduced exploration general and administrative expense.

The earnings increase was partly offset by lower prices across all commodities; lower equity earnings from APLNG, mainly as a result of higher DD&A expense from APLNG Trains 1 and 2 coming online; and a third-quarter 2016 deferred tax charge of $174 million resulting from APLNG's tax functional currency change.

Average production increased 15 percent in 2016, compared with 2015. The production increase in 2016 was mainly attributable to new production from the ramp-up of APLNG in Australia and the Kebabangan gas field in Malaysia, improved drilling and well performance in China and Malaysia, and increased recoveries from production sharing contracts in Indonesia. The production increase was partially offset by normal field decline across the segment.

Other International

	2017	2016	2015
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ 167**	(16)	(593)
Average Net Production			
Crude oil (MBD)			
Equity affiliates	**-**	-	4
Total Production (MBOED)	**-**	-	4
Average Sales Prices			
Crude oil (dollars per barrel)			
Equity affiliates	**-**	-	37.21

The Other International segment includes exploration activities in Colombia and Chile.

2017 vs. 2016

Other International operations reported earnings of $167 million in 2017, compared with a loss of $16 million in 2016. The increase in earnings was primarily due to a $320 million before- and after-tax ICSID award from an arbitration with The Republic of Ecuador. Earnings were additionally increased due to lower rig stacking costs in Angola. The increase in earnings was partly offset by the absence of a $138 million gain in 2016 on the disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal, and a $45 million tax charge from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the newly enacted Tax Legislation.

2016 vs. 2015

Other International operations reported a loss of $16 million in 2016, compared with a loss of $593 million in 2015. The decrease in losses was primarily due to the absence of after-tax charges in 2015 of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Additionally, losses decreased due to the absence of the 2015 after-tax dry hole expenses offshore Angola of $81 million for the Omosi-1 well and $59 million for the Vali-1 well, combined with a $138 million gain on the 2016 disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal.

Corporate and Other

	Millions of Dollars		
	2017	2016	2015
Net Loss Attributable to ConocoPhillips			
Net interest	**$ (739)**	(980)	(518)
Corporate general and administrative expenses	**(284)**	(289)	(246)
Technology	**20**	50	122
Other	**(1,133)**	(110)	(167)
	$ (2,136)	(1,329)	(809)

2017 vs. 2016

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased 25 percent in 2017 compared with 2016, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest as a result of reduced debt. Higher interest income further drove the decrease in net interest, which was partly offset by lower capitalized interest on projects.

Corporate general and administrative expenses which include pension settlement expenses and compensation program costs was essentially flat in 2017.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, LNG, oil sands and other production operations. Earnings from Technology were $20 million in 2017, compared with $50 million in 2016. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

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 and premiums incurred on the early retirement of debt. “Other” expenses increased $1,023 million in 2017, mainly due to an $813 million tax charge from the revaluation of deferred taxes at a lower federal statutory rate, in accordance with the newly enacted Tax Legislation and premiums on our early retirement of debt.

2016 vs. 2015

Net interest increased 89 percent in 2016 compared with 2015, primarily as a result of the absence of the 2015 impacts from the fair market value of apportioning interest expense in the United States, lower capitalized interest on projects, and increased debt.

Corporate general and administrative expenses increased 17 percent in 2016, mainly due to increases from market impacts on certain compensation programs, partly offset by lower staff expenses.

Earnings from Technology were $50 million in 2016, compared with $122 million in 2015. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

“Other” expenses decreased 34 percent in 2016, mainly due to lower restructuring costs and favorable foreign currency impacts, partly offset by the absence of a 2015 tax benefit.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2017	2016	2015
Net cash provided by operating activities	**$ 7,077**	4,403	7,572
Cash and cash equivalents	**6,325**	3,610	2,368
Short-term debt	**2,575**	1,089	1,427
Total debt	**19,703**	27,275	24,880
Total equity	**30,801**	35,226	40,082
Percent of total debt to capital*	**39 %**	44	38
Percent of floating-rate debt to total debt	**5 %**	9	7

**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 shelf registration statement. In 2017, the primary uses of our available cash were $7,876 million to reduce debt; $4,591 million to support our ongoing capital expenditures and investments program; $1,305 million to pay dividends on our common stock; $1,790 million net purchases of short-term investments; $3,000 million to repurchase our common stock; and a $600 million contribution to our domestic qualified pension plan. During 2017, cash and cash equivalents increased by $2,715 million to $6,325 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 Sources of 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.

Significant Sources of Capital

Operating Activities
During 2017, cash provided by operating activities was $7,077 million, a 61 percent increase from 2016. The increase was primarily due to higher prices across all commodities.

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 natural gas liquids. 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. Our 2017 production averaged 1,377 MBOED. Full-year 2018 production is expected to be 1,195 to 1,235 MBOED. This results in approximately 5 percent growth compared with full-year 2017 underlying production, which excludes the impact of closed and planned dispositions of 191 MBOED. Production guidance for 2018 excludes Libya. 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 total reserve replacement in 2017 was negative 168 percent. Our organic reserve replacement, which excludes the impact of sales and purchases, was 200 percent in 2017. Over the five-year period ended December 31, 2017, our reserve replacement was a negative 24 percent (including 3 percent from consolidated operations) reflecting the impact of asset dispositions and lower prices. The total reserve replacement amount above is based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. For additional information about our 2018 capital budget, see the “2018 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. In 2017, revisions increased reserves, while in 2016 and 2015, revisions decreased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Investing Activities
Proceeds from asset sales in 2017 were $13.9 billion. 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 $11.0 billion in cash after customary adjustments and 208 million Cenovus Energy common shares. We completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company. Total proceeds for the sale was $2.5 billion in cash after customary adjustments. We also completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

Proceeds from asset dispositions in 2016 were $1.3 billion, primarily from the sales of ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal; our 40 percent interest in South Natuna Sea Block B in Indonesia; our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet; and certain mineral and non-mineral fee lands in northeastern Minnesota.

For additional information on our dispositions and investment in Cenovus common shares, see Note 4—Assets Held for Sale, Sold or Acquired and Note 6—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, and the Results of Operations section within Management’s Discussion and Analysis.

Commercial Paper and Credit Facilities
We have a revolving credit facility totaling $6.75 billion, expiring in June 2019. 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 programs. 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 United States. 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 two commercial paper programs. The ConocoPhillips $6.25 billion commercial paper program is available to fund short-term working capital needs. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding at December 31, 2017 or 2016, under either the ConocoPhillips or the ConocoPhillips Qatar Funding Ltd. commercial paper program. We had no direct borrowings or letters of credit issued under the revolving credit facility. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2017.

In the first quarter of 2017, Fitch and Standard & Poor’s reflected an improvement in their outlook for our debt from “negative” to “stable” and affirmed our long-term debt rating at “A-.” In January 2018, Fitch further improved their outlook for our debt from “stable” to “positive.” After improving their outlook for our debt from “negative” to “positive” in the first quarter of 2017, Moody’s Investor Services upgraded our long-term debt rating from “Baa2” to “Baa1” with a stable outlook in the third quarter of 2017 in response to our debt reduction. 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, 2017 and 2016, we had direct bank letters of credit of $338 million and $304 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 U.S. Securities and Exchange Commission (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 11—Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

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Capital Requirements

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

Our debt balance at December 31, 2017, was $19.7 billion, a decrease of $7.6 billion from the balance at December 31, 2016.

In 2017, two notes totaling $1,001 million were paid at maturity, including the $1.0 billion 1.05% Notes due 2017. Also in 2017, we prepaid the $1,450 million term loan facility due in 2019. We also redeemed a total $5.0 billion of debt, described below, incurring $301 million in premiums above book value, which are reported in the “Other expense” line on our consolidated income statement.

- 6.65% Debentures due 2018 with principal of $297 million.
- 5.20% Notes due 2018 with principal of $500 million.
- 1.5% Notes due 2018 with principal of $750 million.
- 5.75% Notes due 2019 with principal of $2.25 billion.
- 6.00% Notes due 2020 with principal of $1.0 billion.
- 4.20% Notes due 2021 with principal of $1.25 billion (partial redemption of $250 million).

In the fourth quarter of 2017, we gave notice to redeem the following debt instruments totaling $2.25 billion.

- 2.2% Notes due 2020 with principal of $500 million.
- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.

The prepayments occurred on January 22, 2018, and we incurred premiums above book value of $75 million.

On a longer-term basis our debt target is $15 billion by year-end 2019. In the future, we may redeem other debt instruments or purchase debt instruments in the open market or otherwise, as we seek to achieve this target. Any such redemptions or purchases would be subject to market conditions and other factors, and may be conducted or discontinued at any time without prior notice. For more information on Debt, see Note 10—Debt, in the Notes to Consolidated Financial Statements.

On January 31, 2017, we announced a 6 percent increase in the quarterly dividend to $0.265 per share. The dividend was paid on March 1, 2017, to stockholders of record at the close of business on February 14, 2017. On May 5, 2017, we announced a quarterly dividend of $0.265 per share. The dividend was paid on June 1, 2017, to stockholders of record at the close of business on May 15, 2017. On July 12, 2017, we announced a quarterly dividend of $0.265 per share. The dividend was paid on September 1, 2017, to stockholders of record at the close of business on July 24, 2017. On October 6, 2017, we announced a quarterly dividend of $0.265 per share which was paid on December 1, 2017, to stockholders of record at the close of business on October 16, 2017. Additionally, on February 1, 2018, we announced an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share. The dividend is payable on March 1, 2018, to stockholders of record at the close of business on February 12, 2018.

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion, with the remaining balance to be repurchased in 2019. Since our share repurchase program began in November 2016, we have repurchased 66 million shares at a cost of $3.1 billion through December 31, 2017.

In addition to our previously announced share repurchase program above, we are currently planning to purchase up to an additional $1.5 billion of our common stock through 2020. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including Board authorization, market conditions and other factors. See Risk Factors “Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.”

During the third quarter of 2017, we made a $600 million contribution to our domestic qualified pension plan, which is included in the “Other” line in the “Cash Flows From Operating Activities” section of our

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consolidated statement of cash flows. This additional contribution significantly lowers our domestic pension deficit which will reduce future premiums charged by the Pension Benefit Guaranty Corporation. It also mitigates the need for contributions in future quarters.

Contractual Obligations

The table below summarizes our aggregate contractual fixed and variable obligations as of December 31, 2017:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Years 2–3	Years 4–5	After 5 Years
Debt obligations (a)	$ 18,929	2,508	63	1,706	14,652
Capital lease obligations (b)	774	67	147	132	428
Total debt	19,703	2,575	210	1,838	15,080
Interest on debt and other obligations	13,884	955	1,881	1,834	9,214
Operating lease obligations (c)	1,548	278	628	433	209
Purchase obligations (d)	10,102	4,210	1,833	945	3,114
Other long-term liabilities					
Pension and postretirement benefit contributions (e)	1,312	210	491	611	–
Asset retirement obligations (f)	7,798	251	687	575	6,285
Accrued environmental costs (g)	180	25	36	29	90
Unrecognized tax benefits (h)	51	51	(h)	(h)	(h)
Total	$ 54,578	8,555	5,766	6,265	33,992

(a) Includes $252 million of net unamortized premiums, discounts and debt issuance costs. See Note 10—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(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 $3,487 million.

Purchase obligations of $5,443 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 2018 through 2022. For additional information related to expected benefit payments subsequent to 2022, see Note 17—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

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(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 $831 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

	Millions of Dollars		
	2017	2016	2015
Alaska	$ **815**	883	1,352
Lower 48	**2,136**	1,262	3,765
Canada	**202**	698	1,255
Europe and North Africa	**872**	1,020	1,573
Asia Pacific and Middle East	**482**	838	1,812
Other International	**21**	104	173
Corporate and Other	**63**	64	120
Capital Program	$ **4,591**	4,869	10,050

Our capital expenditures and investments for the three-year period ended December 31, 2017, totaled $19.5 billion. The 2017 expenditures supported key exploration and developments, primarily:

- Oil and natural gas development and exploration and appraisal activities in the Lower 48, including Eagle Ford, Bakken, the Permian Basin, the Niobrara in the Denver-Julesburg Basin and several emerging plays.
- Alaska activities related to development in the Western North Slope, Greater Kuparuk Area, and the Greater Prudhoe Area.
- Development activities in Europe, including the Greater Ekofisk Area, Clair Ridge, Aasta Hansteen, and Heidrun.
- Continued oil sands development and appraisal activities in liquids-rich plays in Canada.
- Continued development in Malaysia, Indonesia, China, and Australia; appraisal activity in Australia and exploration activity in Malaysia.

2018 CAPITAL BUDGET

In November 2017, we announced a 2018 capital budget of $5.5 billion, including $3.5 billion of sustaining capital and $2 billion in accretive, short-cycle unconventional programs, future major projects and exploration activities.

We are planning to allocate approximately:

- 51 percent of our 2018 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford, Bakken and Permian, as well as development drilling in Australia/Timor-Leste, Norway and Alaska.

- 18 percent of our 2018 capital expenditures budget to maintain base production and corporate expenditures.
- 17 percent of our 2018 capital expenditures budget to major projects. These funds will focus on major projects in China, Alaska, Europe and Malaysia.
- 8 percent of our 2018 capital expenditures budget to new exploration activity, primarily in Alaska and the Lower 48.
- 6 percent of our 2018 capital expenditures budget to development appraisal, including the Lower 48, Canada and Alaska.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the "Oil and Gas Operations" section.

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 12—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, 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 18—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 United States.
- 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. 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, water quality standards and stricter fuel regulations, 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 United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States 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 the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, 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, 2017, there were 14 sites around the United States 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 $398 million in 2017 and are expected to be about $451 million per year in 2018 and 2019. Capitalized environmental costs were $170 million in 2017 and are expected to be about $223 million per year in 2018 and 2019.

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. 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, 2017, our balance sheet included total accrued environmental costs of $180 million, compared with $247 million at December 31, 2016, 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
There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (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 European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2017 was approximately $1.5 million (net share before-tax).
- The Alberta Specified Gas Emitter regulations require any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide or equivalent per year to reduce its net emissions intensity from its baseline. The reduction requirement increased from 15 percent in 2016 to 20 percent in 2017. The total cost of compliance with these regulations in 2017 was approximately $3 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirming 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 2017 was approximately $29 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 $1 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.

In the United States, 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.

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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 corporate Climate Change Action Plan, together with individual business unit climate change management plans in order to undertake actions in four major areas:

- Equipping the company for a low emission world, for example by integrating GHG forecasting and reporting into company procedures; utilizing GHG pricing in planning economics; and developing systems to handle GHG market transactions.
- Reducing GHG emissions—In 2016, the company reduced or avoided GHG emissions by approximately 114,000 metric tonnes by carrying out a range of programs across our business units. In 2017, we set a long-term target to reduce our greenhouse gas emissions intensity between 5 percent and 15 percent by 2030 from a 2017 baseline. Setting such a target demonstrates our continuing systematic approach to managing climate-related risks throughout the business.
- Evaluating business opportunities such as the creation of offsets and allowances, the use of low carbon energy and the development of low carbon technologies.
- Engaging externally—The company is a sponsor of MIT's Joint Program on the Science and Policy of Global Change; constructively engages in the development of climate change legislation and regulation; and discloses our progress and performance through the Carbon Disclosure Project and the Dow Jones Sustainability Index.

The company uses an estimated market cost of GHG emissions of $40 per metric tonne to evaluate future projects and opportunities.

In 2017 and early 2018, cities and/or counties in California and New York have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips will be vigorously defending 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.

NEW ACCOUNTING STANDARDS

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, "Leases" (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB Accounting Standards Codification (ASC) Topic 840, "Leases," and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. In January 2018, ASU No. 2016-02 was amended by the provisions of ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842." We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, and continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. We also continue to monitor proposals issued by the FASB to clarify the ASU and certain industry implementation issues. While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures. For additional information, see Note 24—New Accounting Standards, in the Notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles 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 discussions of contingencies and 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 discovered on the prospect.

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 2017, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $503 million and the accumulated impairment reserve was $130 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 57 percent, and the weighted-average amortization period was approximately three years. If that judgmental percentage were to be raised by 5 percent across all calculations, before-tax leasehold impairment expense in 2018 would increase by approximately $6 million. At year-end 2017, the remaining $3,249 million 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 $2.4 billion is concentrated in nine major development areas, the majority of which are not expected to move to proved properties in 2018. 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 2017, total suspended well costs were $853 million, compared with $1,063 million at year-end 2016. For additional information on suspended wells, including an aging analysis, see Note 7—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 production sharing contracts, 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 2017, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $41 billion and the DD&A recorded on these assets in 2017 was approximately $6.4 billion. The estimated proved developed reserves for our consolidated operations were 3.7 billion BOE at the end of 2016 and 3.0 billion BOE at the end of 2017. 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 2017 would have increased by an estimated $726 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 exploration and production 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 8—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 5—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 United States 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 9—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 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,200 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $110 million, while a 1 percent 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 elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, we could recognize a curtailment gain or loss. See Note 17—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."

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 natural gas liquids 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 natural gas liquids, 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 exploration and production 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 natural gas liquids.
- Inability to timely obtain or maintain permits, including those necessary for construction, drilling and/or development; failure to comply with applicable laws and regulations; 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, terrorism, cyber attacks, and information technology failures, constraints or disruptions.
- Changes in international monetary conditions and foreign currency exchange rate fluctuations.

- Reduced demand for our products or the use of competing energy products, including alternative energy sources.
- Substantial investment in and development of 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 environmental regulations.
- Liability resulting from litigation.
- 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 natural gas liquids pricing, regulation or taxation; 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 in the oil and gas exploration and production industry.
- Any limitations on our access to capital or increase in our cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Our inability to execute, or delays in the completion, of any asset dispositions we elect to pursue.
- Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for asset dispositions 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, 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.
- Our inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A—Risk Factors in our 2017 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

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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 of Finance, Commercial, and Chief Financial Officer, who reports to the Chief Executive Officer, monitor 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, 2017, 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, 2017 and 2016, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk
The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of 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 financial instruments is estimated based on quoted market prices.

Expected Maturity Date	Millions of Dollars Except as Indicated					
	Debt					
	Fixed Rate Maturity	Average Interest Rate		Floating Rate Maturity	Average Interest Rate	
Year-End 2017						
2018	**$ 2,250**	**3.31**	**%**	**$ 250**	**1.75**	**%**
2019	**23**	**-**		**-**	**-**	
2020	**-**	**-**		**-**	**-**	
2021	**150**	**9.13**		**-**	**-**	
2022	**1,014**	**2.45**		**500**	**2.32**	
Remaining years	**14,207**	**6.00**		**283**	**1.70**	
Total	**$ 17,644**			**$ 1,033**		
Fair value	**$ 21,402**			**$ 1,033**		
Year-End 2016						
2017	$ 1,001	1.06	%	$ -	-	%
2018	1,570	3.63		250	1.24	
2019	2,250	5.75		1,450	2.31	
2020	1,500	4.73		-	-	
2021	2,150	4.08		-	-	
Remaining years	15,221	5.77		783	1.43	
Total	$ 23,692			$ 2,483		
Fair value	$ 26,824			$ 2,483		

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 available-for-sale securities.

At December 31, 2017 and 2016, 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, 2017, we had outstanding foreign currency zero-cost collars buying the right to sell $1.25 billion Canadian dollars (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 as at December 31, 2017, was a before-tax loss of $9 million. Based on an adverse hypothetical 10 percent change in the December 2017 exchange rate, this would result in an additional before-tax loss of $74 million. 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.

At December 31, 2016, we had outstanding foreign currency exchange forward-swap contracts. Since the gain or loss on the swaps was offset from remeasuring the related cash balances and since our aggregate position in the forwards was not material, there would have been no impact to our income from an adverse hypothetical 10 percent change in the December 2016 exchange rates.

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The gross notional and fair market values of these positions at December 31, 2017 and 2016, were as follows:

Foreign Currency Exchange Derivatives	In Millions				
	Notional*			Fair Market Value**	
		2017	2016	**2017**	2016
Sell U.S. dollar, buy Canadian dollar	USD	**-**	13	**-**	-
Buy U.S. dollar, sell British pound	USD	**-**	25	**-**	-
Sell Canadian dollar, buy U.S. dollar	CAD	**1,250**	-	**(9)**	-
Buy Canadian dollar, sell U.S. dollar	CAD	**25**	-	**1**	-
Buy British pound, sell Canadian dollar	GBP	**-**	1,069	**-**	(168)
Sell British pound, buy Norwegian krone	GBP	**-**	51	**-**	1
Sell British pound, buy Euro	GBP	**1**	-	**-**	-

**Denominated in U.S. dollars (USD), British pound (GBP) and Canadian dollars (CAD).*
***Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 13—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

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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, 2017. 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, 2017.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2017, and their report is included herein.

/s/ Ryan M. Lance	/s/ Don E. Wallette, Jr.
Ryan M. Lance	**Don E. Wallette, Jr.**
Chairman and Chief Executive Officer	Executive Vice President, Finance, Commercial and Chief Financial Officer

February 20, 2018

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 as of December 31, 2017 and 2016, and 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, 2017, 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 "financial statements"). In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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), ConocoPhillips' internal control over financial reporting as of December 31, 2017, 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 20, 2018, expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of ConocoPhillips' management. Our responsibility is to express an opinion on ConocoPhillips' 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 ConocoPhillips 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.

/s/ Ernst & Young LLP

We have served as ConocoPhillips' auditor since 1949.

Houston, Texas
February 20, 2018

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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, 2017, 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, 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 as of December 31, 2017 and 2016, and 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, 2017, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) of ConocoPhillips and our report dated February 20, 2018, expressed an unqualified opinion thereon.

Basis for Opinion

ConocoPhillips' 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 ConocoPhillips' 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 ConocoPhillips 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 20, 2018

Consolidated Income Statement   ConocoPhillips

Years Ended December 31

	Millions of Dollars		
	2017	2016	2015
Revenues and Other Income			
Sales and other operating revenues	**$ 29,106**	23,693	29,564
Equity in earnings of affiliates	**772**	52	655
Gain on dispositions	**2,177**	360	591
Other income	**529**	255	125
Total Revenues and Other Income	**32,584**	24,360	30,935
Costs and Expenses			
Purchased commodities	**12,475**	9,994	12,426
Production and operating expenses	**5,173**	5,667	7,016
Selling, general and administrative expenses	**561**	723	953
Exploration expenses	**938**	1,915	4,192
Depreciation, depletion and amortization	**6,845**	9,062	9,113
Impairments	**6,601**	139	2,245
Taxes other than income taxes	**809**	739	901
Accretion on discounted liabilities	**362**	425	483
Interest and debt expense	**1,098**	1,245	920
Foreign currency transaction (gains) losses	**35**	(19)	(75)
Other expense	**302**	-	-
Total Costs and Expenses	**35,199**	29,890	38,174
Loss before income taxes	**(2,615)**	(5,530)	(7,239)
Income tax benefit	**(1,822)**	(1,971)	(2,868)
Net loss	**(793)**	(3,559)	(4,371)
Less: net income attributable to noncontrolling interests	**(62)**	(56)	(57)
Net Loss Attributable to ConocoPhillips	**$ (855)**	(3,615)	(4,428)
Net Loss Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*			
Basic	**$ (0.70)**	(2.91)	(3.58)
Diluted	**(0.70)**	(2.91)	(3.58)
Dividends Paid Per Share of Common Stock *(dollars)*	**$ 1.06**	1.00	2.94
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,221,038**	1,245,440	1,241,919
Diluted	**1,221,038**	1,245,440	1,241,919

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income ConocoPhillips

Years Ended December 31

	Millions of Dollars		
	2017	2016	2015
Net Loss	**$ (793)**	(3,559)	(4,371)
Other comprehensive income (loss)			
Defined benefit plans			
Prior service credit arising during the period	**2**	23	301
Reclassification adjustment for amortization of prior service credit included in net loss	**(38)**	(35)	(19)
Net change	**(36)**	(12)	282
Net actuarial gain (loss) arising during the period	**19**	(481)	592
Reclassification adjustment for amortization of net actuarial losses included in net loss	**247**	309	403
Net change	**266**	(172)	995
Nonsponsored plans*	**(2)**	2	1
Income taxes on defined benefit plans	**(81)**	78	(460)
Defined benefit plans, net of tax	**147**	(104)	818
Unrealized holding loss on securities	**(58)**	-	-
Unrealized loss on securities, net of tax	**(58)**	-	-
Foreign currency translation adjustments	**586**	153	(5,199)
Reclassification adjustment for gain included in net loss	**-**	5	-
Income taxes on foreign currency translation adjustments	**-**	-	36
Foreign currency translation adjustments, net of tax	**586**	158	(5,163)
Other Comprehensive Income (Loss), Net of Tax	**675**	54	(4,345)
Comprehensive Loss	**(118)**	(3,505)	(8,716)
Less: comprehensive income attributable to noncontrolling interests	**(62)**	(56)	(57)
Comprehensive Loss Attributable to ConocoPhillips	**$ (180)**	(3,561)	(8,773)

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet ConocoPhillips

At December 31	Millions of Dollars	
	2017	2016
Assets		
Cash and cash equivalents	**$ 6,325**	3,610
Short-term investments	**1,873**	50
Accounts and notes receivable (net of allowance of $4 million in 2017 and $5 million in 2016)	**4,179**	3,249
Accounts and notes receivable—related parties	**141**	165
Investment in Cenovus Energy	**1,899**	-
Inventories	**1,060**	1,018
Prepaid expenses and other current assets	**1,035**	517
Total Current Assets	**16,512**	8,609
Investments and long-term receivables	**9,599**	21,091
Loans and advances—related parties	**461**	581
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $64,748 million in 2017 and $73,075 million in 2016)	**45,683**	58,331
Other assets	**1,107**	1,160
Total Assets	**$ 73,362**	89,772
Liabilities		
Accounts payable	**$ 4,009**	3,631
Accounts payable—related parties	**21**	22
Short-term debt	**2,575**	1,089
Accrued income and other taxes	**1,038**	484
Employee benefit obligations	**725**	689
Other accruals	**1,029**	994
Total Current Liabilities	**9,397**	6,909
Long-term debt	**17,128**	26,186
Asset retirement obligations and accrued environmental costs	**7,631**	8,425
Deferred income taxes	**5,282**	8,949
Employee benefit obligations	**1,854**	2,552
Other liabilities and deferred credits	**1,269**	1,525
Total Liabilities	**42,561**	54,546
Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2017—1,785,419,175 shares; 2016—1,782,079,107 shares)		
Par value	**18**	18
Capital in excess of par	**46,622**	46,507
Treasury stock (at cost: 2017—608,312,034 shares; 2016—544,809,771 shares)	**(39,906)**	(36,906)
Accumulated other comprehensive loss	**(5,518)**	(6,193)
Retained earnings	**29,391**	31,548
Total Common Stockholders' Equity	**30,607**	34,974
Noncontrolling interests	**194**	252
Total Equity	**30,801**	35,226
Total Liabilities and Equity	**$ 73,362**	89,772

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows   ConocoPhillips

Years Ended December 31	Millions of Dollars		
	2017	2016	2015
Cash Flows From Operating Activities			
Net loss	**$ (793)**	(3,559)	(4,371)
Adjustments to reconcile net loss to net cash provided by operating activities			
Depreciation, depletion and amortization	**6,845**	9,062	9,113
Impairments	**6,601**	139	2,245
Dry hole costs and leasehold impairments	**566**	1,184	3,065
Accretion on discounted liabilities	**362**	425	483
Deferred taxes	**(3,681)**	(2,221)	(2,772)
Undistributed equity earnings	**(232)**	299	101
Gain on dispositions	**(2,177)**	(360)	(591)
Other	**(429)**	(85)	321
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**(886)**	820	1,810
Decrease (increase) in inventories	**(55)**	44	166
Decrease in prepaid expenses and other current assets	**69**	105	239
Increase (decrease) in accounts payable	**265**	(524)	(1,647)
Increase (decrease) in taxes and other accruals	**622**	(926)	(590)
Net Cash Provided by Operating Activities	**7,077**	4,403	7,572
Cash Flows From Investing Activities			
Capital expenditures and investments	**(4,591)**	(4,869)	(10,050)
Working capital changes associated with investing activities	**132**	(331)	(968)
Proceeds from asset dispositions	**13,860**	1,286	1,952
Net purchases of short-term investments	**(1,790)**	(51)	-
Collection of advances/loans—related parties	**115**	108	105
Other	**36**	(2)	306
Net Cash Provided by (Used in) Investing Activities	**7,762**	(3,859)	(8,655)
Cash Flows From Financing Activities			
Issuance of debt	**-**	4,594	2,498
Repayment of debt	**(7,876)**	(2,251)	(103)
Issuance of company common stock	**(63)**	(63)	(82)
Repurchase of company common stock	**(3,000)**	(126)	-
Dividends paid	**(1,305)**	(1,253)	(3,664)
Other	**(112)**	(137)	(78)
Net Cash Provided by (Used in) Financing Activities	**(12,356)**	764	(1,429)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**232**	(66)	(182)
Net Change in Cash and Cash Equivalents	**2,715**	1,242	(2,694)
Cash and cash equivalents at beginning of period	**3,610**	2,368	5,062
Cash and Cash Equivalents at End of Period	**$ 6,325**	3,610	2,368

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, 2014	$ 18	46,071	(36,780)	(1,902)	44,504	362	52,273
Net income (loss)					(4,428)	57	(4,371)
Other comprehensive loss				(4,345)			(4,345)
Dividends paid					(3,664)		(3,664)
Distributions to noncontrolling interests and other						(100)	(100)
Distributed under benefit plans		286					286
Other					2	1	3
December 31, 2015	$ 18	46,357	(36,780)	(6,247)	36,414	320	40,082
Net income (loss)					(3,615)	56	(3,559)
Other comprehensive income				54			54
Dividends paid					(1,253)		(1,253)
Repurchase of company common stock			(126)				(126)
Distributions to noncontrolling interests and other						(124)	(124)
Distributed under benefit plans		150					150
Other					2		2
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					**(1,305)**		**(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**

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 either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. 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 23—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 income in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Most 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 United States 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 sales of crude oil, bitumen, natural gas, liquefied natural gas (LNG), natural gas liquids and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

  Revenues associated with producing properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

  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 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 recorded as a component of revenue.

- **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**—Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

- **Inventories**—We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Our commodity-related inventories are recorded at cost primarily using the last-in, first-out (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 first-in, first-out (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 properties, plants and equipment (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 7—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 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 exploration and production 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.

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- **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, 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. For additional information, see Note 9—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—Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

Australia Pacific LNG Pty Ltd (APLNG)
APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2017, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 5—Investments, Loans and Long-Term Receivables, and Note 11—Guarantees, for additional information.

Marine Well Containment Company, LLC (MWCC)
MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. 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 and exercise significant influence through our permanent seat on the ten-member Executive Committee responsible for overseeing the affairs of MWCC. In 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. 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.

At December 31, 2017, the book value of our equity method investment in MWCC was $139 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.

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Note 3—Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2017	2016
Crude oil and natural gas	**$ 512**	418
Materials and supplies	**548**	600
	$ 1,060	1,018

Inventories valued on the LIFO basis totaled $341 million and $269 million at December 31, 2017 and 2016, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $124 million and $104 million at December 31, 2017 and December 31, 2016, respectively. In 2017, liquidation of LIFO inventory values increased the net loss attributable to ConocoPhillips by $1 million.

Note 4—Assets Held for Sale, Sold or Acquired

Assets Held for Sale

In the second quarter of 2017, we signed a definitive agreement to sell our interest in the Barnett. We terminated this agreement in the fourth quarter of 2017 and are continuing to market the asset in 2018. In connection with the signing of the definitive agreement, we recorded a before-tax impairment of $572 million to reduce the carrying value of our investment to estimated fair value. As of December 31, 2017, our Barnett interests had a net carrying value of approximately $291 million and were considered held for sale resulting in the reclassification of $339 million of PP&E to "Prepaid expenses and other current assets" and $48 million of noncurrent liabilities, primarily asset retirement obligations (ARO), to "Other accruals" on our consolidated balance sheet. The before-tax loss associated with our interests in the Barnett, including the $572 million impairment noted above, was $566 million, $66 million, and $58 million for the years ended December 31, 2017, 2016 and 2015, respectively. The Barnett results of operations are reported within our Lower 48 segment.

In addition to the Barnett, certain other properties in our Lower 48 segment met the criteria for assets held for sale at December 31, 2017. These properties had a net carrying value of approximately $212 million after recording a before-tax impairment of $78 million to reduce the carrying value to estimated fair value in the fourth quarter of 2017. We reclassified $238 million of PP&E to "Prepaid expenses and other current assets" and $26 million of noncurrent liabilities, primarily AROs, to "Other accruals" on our consolidated balance sheet. In January 2018, we completed the sale of a portion of these properties for net proceeds of $112 million.

Assets Sold

All gains or losses 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.

2017

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 New York Stock Exchange. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel.

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 before-tax gain of $2.1 billion was included in the "Gain on disposition" line on our consolidated income statement in 2017. We reported before-tax losses of $26 million, $572 million and $582 million for the western Canada gas producing properties for the years ended December 31, 2017, 2016 and 2015, respectively. We reported before-tax equity earnings of $197 million, $89 million and $78 million for FCCL for the same periods, respectively. Both FCCL and the western Canada gas assets were reported within our Canada segment.

For more information on the Canada disposition and our investment in Cenovus Energy see Note 6—Investment in Cenovus Energy, Note 14—Fair Value Measurement, and Note 19—Accumulated Other Comprehensive Loss.

On July 31, 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 million British thermal units.

In the second quarter of 2017, we recorded a before-tax 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, $239 million and $99 million for the years ended December 31, 2017, 2016 and 2015, respectively. The San Juan Basin results of operations were reported within our Lower 48 segment.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments, and recognized a before-tax 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 before-tax losses for the Panhandle properties of $14 million, $21 million, and $41 million for the years ended December 31, 2017, 2016 and 2015, respectively. The Panhandle results were reported within our Lower 48 segment.

2016

In April 2016, we sold our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet for $134 million, net of settlement of gas imbalances and customary adjustments, and recognized a gain on disposition of $56 million. At the time of disposition, the net carrying value of our Beluga River Unit interest, which was included in the Alaska segment, was $78 million, consisting primarily of $100 million of PP&E and $19 million of AROs.

In October 2016, we completed an asset exchange with Bonavista Energy in which we gave up approximately 141,000 net acres of noncore developed properties in central Alberta in exchange for approximately 40,000 net acres of primarily undeveloped properties in northeast British Columbia. The fair value of the transaction was determined to be approximately $69 million and a before-tax impairment of $57 million was recognized in the third quarter of 2016 when the assets were considered held for sale, to reduce the carrying value to fair value. A loss on disposition of approximately $1 million was recognized upon completion of the transaction. The divested properties were included in the Canada segment.

Also in October 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal for $442 million and recognized a gain on disposition of $146 million. At the time of disposition, the carrying value of our interest was $286 million, which was primarily PP&E. Senegal results of operations were reported within our Other International segment.

In November 2016, we completed the sale of our 40 percent interest in South Natuna Sea Block B for $225 million and recognized a loss on disposition of $26 million. Our interest in Block B was included in the Asia Pacific and Middle East segment. In 2016, we recognized a before-tax impairment of $42 million at the time it was considered held for sale to reduce the carrying value to fair value. At the time of the disposition, the carrying value of our interest was approximately $251 million, which included primarily $154 million of PP&E, $178 million of accounts receivable, $25 million of inventory, $54 million of deferred tax assets, $130 million of accounts payable and other accruals, and $38 million of employee benefit obligations.

In December 2016, we completed the sale of certain mineral and non-mineral fee lands in northeastern Minnesota, which were included in the Lower 48 segment, for $148 million and recorded a gain on disposition of $4 million. The majority of the assets sold were acquired during the fourth quarter of 2016 as a result of ConocoPhillips holding a reversionary interest in the Greater Northern Iron Ore Properties Trust (the Trust), a grantor trust that owned mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. In November 2016, upon completion of the wind-down period, documents memorializing ConocoPhillips' ownership of certain Trust property, including all of the Trust's mineral properties and active leases, were delivered to us and we recognized the fair value of the net assets resulting in a gain of $88 million recorded in the "Other income" line on our consolidated income statement. At the time of the disposition, the carrying value of our interests, which included the assets obtained from the Trust, consisted of $144 million of PP&E.

2015
In November 2015, we sold a portion of our western Canadian properties located in British Columbia, Alberta, and Saskatchewan for $198 million and recognized a gain on disposition of $66 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was $132 million, which included primarily $379 million of PP&E and $248 million of ARO.

In December 2015, we sold a portion of our western Canadian properties located in central Alberta for $130 million and recognized a loss on disposition of $235 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was approximately $365 million, which included primarily $488 million of PP&E and $126 million of ARO.

Additionally, other December 2015 disposition transactions are summarized below.

We sold producing properties in East Texas and North Louisiana for $412 million and recognized a gain on disposition of $189 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $223 million, which included $351 million of PP&E and $128 million of ARO.

We sold certain gas producing properties in South Texas for $358 million and recognized a gain on disposition of $201 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $157 million, which included $369 million of PP&E and $212 million of ARO.

We sold certain pipeline and gathering assets in South Texas for $201 million and recognized a gain on disposition of $193 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $8 million, which primarily included $24 million of PP&E and $18 million of ARO.

We also sold our 50 percent interest in the Russian joint venture, Polar Lights Company, for $98 million and recognized a gain on disposition of $58 million. At the time of the disposition, the carrying value of our equity method investment in Polar Lights Company, which was included in our Other International segment, was approximately $40 million.

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Acquisition
In January 2018, we entered into an agreement to acquire certain oil and gas assets in Alaska for $400 million, subject to customary adjustments. The acquisition is subject to regulatory approval.

Note 5—Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2017	2016
Equity investments	**$ 9,129**	20,364
Loans and advances—related parties	**461**	581
Long-term receivables	**375**	631
Other investments	**95**	96
	$ 10,060	21,672

Equity Investments
Affiliated companies in which we had a significant equity investment at December 31, 2017, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent)—to develop coalbed methane production 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		
	2017	2016	2015
Revenues	**$ 11,554**	10,149	11,003
Income (loss) before income taxes	**(2,875)**	660	1,866
Net income (loss)	**(1,431)**	799	1,801

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

	Millions of Dollars	
	2017	2016
Current assets	**$ 2,920**	3,578
Noncurrent assets	**42,693**	60,243
Current liabilities	**2,453**	2,352
Noncurrent liabilities	**25,522**	23,764

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

At December 31, 2017, retained earnings included $20 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $605 million, $398 million and $876 million in 2017, 2016 and 2015, respectively.

APLNG

APLNG is focused on coalbed methane 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 coalbed methane 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 is 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, 2017, all amounts have been drawn from the facility. APLNG made its first principal and interest repayment in March 2017, and will continue to make bi-annual payments until March 2029. At December 31, 2017, a balance of $7.9 billion was outstanding on the facility. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for Train 2, which removed the remaining guarantee. See Note 11—Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 2—Variable Interest Entities (VIEs) for additional information.

On July 1, 2016, APLNG changed its tax functional currency from Australian dollar to U.S. dollar and translated all APLNG assets and liabilities into U.S. dollar, utilizing the exchange rate as of that date. As a result of this change, we recorded a reduction to our investment in APLNG for the deferred tax effect of $174 million in the "Equity in earnings of affiliates" line of our consolidated income statement.

During the fourth quarter of 2015, due to the outlook for crude oil and natural gas prices at that time, the estimated fair value of our investment in APLNG declined to an amount below book value. Accordingly, we recorded a noncash $1,502 million before- and after-tax impairment, in our fourth-quarter 2015 results.

During the first and second quarters 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 Financial Accounting Standards Board (FASB) Accounting Standards Codification (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, 2017, the carrying value of our equity method investment in APLNG was $7,669 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $7,213 million, resulting in a basis difference of $456 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 loss attributable to ConocoPhillips for 2017, 2016 and 2015 was after-tax expense of $100 million, $92 million and $21 million, respectively, representing the amortization of this basis difference on currently producing licenses.

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 4—Assets Held for Sale, Sold or Acquired and Note 6—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 $581 million as described below under "Loans and Long-Term Receivables." At December 31, 2017, the book value of our equity method investment in QG3, excluding the project financing, was $886 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

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, 2017, significant loans to affiliated companies include $581 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."

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Note 6—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 approximated 16.9 percent of issued and outstanding Cenovus common shares at closing. See Note 4—Assets Held for Sale, Sold or Acquired, for additional information on the Canada disposition.

At closing, 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 New York Stock Exchange.

We have classified our investment as an available-for-sale equity security on our consolidated balance sheet and, as of December 31, 2017, our investment is carried at fair value of $1.90 billion, reflecting the closing price of Cenovus Energy shares on the New York Stock Exchange of $9.13 per share. The carrying value reflects a before-tax and after-tax unrealized loss of $58 million over our cost basis of $1.96 billion. The unrealized loss is reported as a component of accumulated other comprehensive loss. See Note 14—Fair Value Measurement, for additional information. We intend to decrease our investment over time through market transactions, private agreements or otherwise.

Note 7—Suspended Wells and Other Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2017, 2016 and 2015:

	Millions of Dollars		
	2017	2016	2015
Beginning balance at January 1	**$ 1,063**	1,260	1,299
Additions pending the determination of proved reserves	**118**	225	331
Reclassifications to proved properties	**(66)**	(27)	(28)
Sales of suspended well investment	**-**	(247)	-
Charged to dry hole expense	**(262)**	(148)	(342)
Ending balance at December 31	**$ 853**	1,063	1,260

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

	Millions of Dollars		
	2017	2016	2015
Exploratory well costs capitalized for a period of one year or less	**$ 67**	132	235
Exploratory well costs capitalized for a period greater than one year	**786**	931	1,025
Ending balance	**$ 853**	1,063	1,260
Number of projects with exploratory well costs capitalized for a period greater than one year	**23**	26	28

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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, 2017:

	Millions of Dollars			
		Suspended Since		
	Total	2014–2016	2011–2013	2004–2010
Greater Poseidon—Australia(2)	177	63	102	12
Greater Clair—UK(2)	144	99	45	-
Surmont—Canada(1)	117	34	59	24
NPRA—Alaska(1)	114	66	42	6
Barossa/Caldita—Australia(2)	77	-	-	77
Middle Magdalena Basin—Colombia(1)	48	48	-	-
Bohai—China(2)	19	19	-	-
Kamunsu East—Malaysia(2)	19	-	19	-
NC 98—Libya(2)	15	11	-	4
Sunrise—Australia(2)	13	-	-	13
Other of $10 million or less each(1)(2)	43	20	6	17
Total	$ 786	360	273	153

(1)Additional appraisal wells planned.
(2)Appraisal drilling complete; costs being incurred to assess development.

In line with our July 2015 announcement of plans to reduce future deepwater exploration spending, we recognized before-tax cancellation costs of $335 million and wrote off $48 million of before-tax capitalized rig costs in relation to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in the Lower 48 segment in 2015. In July 2016, we entered into an agreement to terminate our final Gulf of Mexico deepwater drillship contract. The drillship, used to drill our operated deepwater well inventory in the Gulf of Mexico through April 2016, was contracted on a shared, three-year term. Accordingly, we recorded before-tax rig cancellation charges and third-party costs of $146 million in our Lower 48 segment in 2016.

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.

Note 8—Impairments

During 2017, 2016 and 2015, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2017	2016	2015
Alaska	**$ 180**	1	10
Lower 48	**3,969**	149	(2)
Canada	**22**	88	4
Europe and North Africa	**46**	(160)	724
Asia Pacific and Middle East	**2,384**	44	1,508
Corporate	**-**	17	1
	$ 6,601	139	2,245

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 4—Assets Held for Sale, Sold or Acquired, 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 United Kingdom 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 5—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.

2016
In the Lower 48, we recorded impairments of $149 million primarily due to cancelled projects associated with plan of development changes for Eagle Ford infrastructure, as well as lower natural gas prices and increased ARO estimates.

In Canada, we recorded impairments of $88 million mainly due to plan of development changes, as well as certain developed properties being written down to fair value less costs to sell.

In Europe and North Africa, we recorded a credit to impairment of $160 million, primarily in the United Kingdom, due to decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years, partly offset by asset impairments due to lower natural gas prices in the United Kingdom.

In Asia Pacific and Middle East, we recorded impairments of $44 million, mainly due to a write-down to fair value less costs to sell of our developed properties in Block B, offshore Indonesia, in the third quarter of 2016.

In Corporate, we recorded impairments of $17 million due to cancelled projects in our Houston and Bartlesville offices.

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.

Charges recorded in exploration expenses in 2016 were related to our decision announced in 2015 to reduce deepwater exploration spending.

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In our Lower 48 segment, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. Additionally, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect and a $79 million before-tax impairment, primarily as a result of changes in the estimated market value following the completion of marketing efforts.

In our Canada segment, we recorded before-tax unproved property impairments of $31 million, primarily due to decisions to discontinue additional testing of undeveloped leaseholds.

2015
See the “APLNG” section of Note 5—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment.

In Europe and North Africa, we recorded impairments of $724 million, primarily in the United Kingdom as a result of lower natural gas prices and increases to AROs.

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 Other International segment, we decided not to pursue further evaluation of our Block 36 and Block 37 leases in Angola due to lack of commerciality of wells. Accordingly, we recorded before-tax impairments of $377 million and $116 million, respectively, for the associated carrying values of capitalized undeveloped leasehold costs.

In our Lower 48 segment, we decided not to conduct further activity on certain Gulf of Mexico leases, given our strategic plans to reduce deepwater exploration spending, and accordingly recorded before-tax impairments of $399 million for the associated carrying value of certain capitalized undeveloped leasehold costs.

In our Asia Pacific and Middle East segment, we decided to relinquish our Palangkaraya PSC in Indonesia. Accordingly, we recorded a before-tax impairment of $105 million for the associated carrying values of capitalized undeveloped leasehold cost.

In our Alaska segment, we recorded a before-tax impairment of $575 million for the associated carrying value of capitalized undeveloped leasehold cost in the Chukchi Sea in Alaska.

In our Canada segment, we recorded a before-tax impairment of $102 million for the Duvernay, Thornbury, Saleski and Crow Lake areas driven primarily by the lack of commerciality of wells.

Note 9—Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2017	2016
Asset retirement obligations	**$ 7,798**	8,405
Accrued environmental costs	**180**	247
Total asset retirement obligations and accrued environmental costs	**7,978**	8,652
Asset retirement obligations and accrued environmental costs due within one year*	**(347)**	(227)
Long-term asset retirement obligations and accrued environmental costs	**$ 7,631**	8,425

**Classified as a current liability on the balance sheet under “Other accruals.”*

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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 2017 and 2016, our overall ARO changed as follows:

	Millions of Dollars	
	2017	2016
Balance at January 1	**$ 8,405**	9,911
Accretion of discount	**358**	420
New obligations	**113**	180
Changes in estimates of existing obligations	**(150)**	(1,197)
Spending on existing obligations	**(152)**	(314)
Property dispositions	**(1,065)**	(150)
Foreign currency translation	**289**	(445)
Balance at December 31	**$ 7,798**	8,405

Accrued Environmental Costs
Total accrued environmental costs at December 31, 2017 and 2016, were $180 million and $247 million, respectively.

We had accrued environmental costs of $105 million and $183 million at December 31, 2017 and 2016, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $60 million and $51 million of environmental costs associated with sites no longer in operation at December 31, 2017 and 2016, respectively. In addition, $15 million and $13 million were included at both December 31, 2017 and 2016, 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 $96 million at December 31, 2017. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $12 million in 2018, $10 million in 2019, $5 million in 2020, $10 million in 2021, $3 million in 2022, and $106 million for all future years after 2022.

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Note 10—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2017	2016
9.125% Debentures due 2021	**$ 150**	150
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.65% Debentures due 2023	**88**	88
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
6.65% Debentures due 2018	**-**	297
6.50% Notes due 2039	**2,750**	2,750
6.00% Notes due 2020	**-**	1,000
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
5.75% Notes due 2019	**-**	2,250
5.20% Notes due 2018	**-**	500
4.95% Notes due 2026	**1,250**	1,250
4.30% Notes due 2044	**750**	750
4.20% Notes due 2021	**1,000**	1,250
4.15% Notes due 2034	**500**	500
3.35% Notes due 2024	**1,000**	1,000
3.35% Notes due 2025	**500**	500
2.875% Notes due 2021	**750**	750
2.4% Notes due 2022	**1,000**	1,000
2.2% Notes due 2020	**500**	500
1.5% Notes due 2018	**-**	750
1.05% Notes due 2017	**-**	1,000
Floating rate term loan due 2019 at 2.31% – 2.75% during 2017 and 1.94% – 2.31% during 2016	**-**	1,450
Floating rate notes due 2018 at 1.24% – 1.75% during 2017 and 0.69% – 1.24% during 2016	**250**	250
Floating rate notes due 2022 at 1.81% – 2.32% during 2017 and 1.26% – 1.81% during 2016	**500**	500
Industrial Development Bonds due 2017 through 2038 at 0.64% – 1.74% during 2017 and 0.01% – 0.91% during 2016	**18**	18
Marine Terminal Revenue Refunding Bonds due 2031 at 0.64% – 1.74% during 2017 and 0.01% – 0.95% during 2016	**265**	265
Other	**23**	24
Debt at face value	**18,677**	26,175
Capitalized leases	**774**	852
Net unamortized premiums, discounts and debt issuance costs	**252**	248

Total debt	**19,703**	27,275
Short-term debt	**(2,575)**	(1,089)
Long-term debt	**$ 17,128**	26,186

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2018 through 2022 are: $2,575 million, $113 million, $97 million, $236 million and $1,602 million, respectively.

We have a revolving credit facility totaling $6.75 billion, expiring in June 2019. 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 programs. 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 United States. 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 two commercial paper programs. The ConocoPhillips $6.25 billion commercial paper program is available to fund short-term working capital needs. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding at December 31, 2017 or 2016, under either the ConocoPhillips or the ConocoPhillips Qatar Funding Ltd. commercial paper program. We had no direct borrowings or letters of credit issued under the revolving credit facility. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2017.

In 2017, two notes totaling $1,001 million were paid at maturity, including the $1.0 billion 1.05% Notes due 2017. Also in 2017, we prepaid the $1,450 million term loan facility due in 2019.

We also redeemed a total $5.0 billion of debt, described below, incurring $301 million in premiums above book value, which are reported in the “Other expense” line on our consolidated income statement.

- 6.65% Debentures due 2018 with principal of $297 million.
- 5.20% Notes due 2018 with principal of $500 million.
- 1.5% Notes due 2018 with principal of $750 million.
- 5.75% Notes due 2019 with principal of $2.25 billion.
- 6.00% Notes due 2020 with principal of $1.0 billion.
- 4.20% Notes due 2021 with principal of $1.25 billion (partial redemption of $250 million).

In the fourth quarter of 2017, we gave notice to redeem the following debt instruments totaling $2.25 billion.

- 2.2% Notes due 2020 with principal of $500 million.
- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.

The prepayments occurred on January 22, 2018, and we incurred premiums above book value of $75 million.

At both December 31, 2017 and 2016, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the “Long-term debt” line on our consolidated balance sheet.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our before-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Our proportionate interest in the FPS is 29 percent as of December 31, 2017. The net carrying value of the capital lease asset was approximately $434 million and $540 million as of December 31, 2017 and 2016, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the "Depreciation, depletion and amortization" line on our consolidated income statement. As of December 31, 2017 and 2016, accumulated depreciation of the capital lease asset amounted to approximately $381 million and $268 million, respectively.

At December 31, 2017, future minimum payments due under capital leases were:

	Millions of Dollars
2018	$ 108
2019	106
2020	106
2021	88
2022	88
Remaining years	487
Total	983
Less: portion representing imputed interest	(209)
Capital lease obligations	$ 774

Note 11—Guarantees

At December 31, 2017, 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, 2017, 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 2017 exchange rates:

- We guaranteed APLNG's performance with regard to a construction contract executed in connection with APLNG's issuance of the Train 1 and Train 2 Notices to Proceed. Our maximum potential amount of future payments related to this guarantee became immaterial in the second quarter of 2017.

- We issued a construction completion guarantee related to the third-party project financing secured by APLNG. In October 2016, we reached financial completion for Train 1, releasing a portion of our guarantee. In August 2017, the two-train project finance lenders' test was completed, releasing the remaining guarantee.

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- 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 12 years. Our maximum exposure under this guarantee is approximately $200 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2017, 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 24 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $960 million ($1.71 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 28 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $150 million and would become payable if APLNG does not perform.

Other Guarantees
We have other guarantees with maximum future potential payment amounts totaling approximately $780 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 5 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.

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, 2017, was approximately $100 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, 2017, were approximately $40 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 12—Contingencies and Commitments.

In 2012, we completed the separation of our downstream business, creating two independent energy companies: ConocoPhillips and Phillips 66. On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream business formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. Our maximum potential liability for future payments under this guarantee, which would become payable if Phillips 66 does not perform its contractual obligations under the supply agreement, is approximately $1.31 billion. At

December 31, 2017, the carrying value of this guarantee is approximately $98 million and the remaining term is seven years. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we have recorded an indemnification asset from Phillips 66 of approximately $98 million. The recorded indemnification asset amount represents the estimated fair value of the guarantee; however, if we are required to perform under the guarantee, we would expect to recover from Phillips 66 any amounts in excess of that value, provided Phillips 66 is a going concern.

Note 12—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 18—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. Environmental Protection Agency (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 9—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, 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, 2017, we had performance obligations secured by letters of credit of $338 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, we announced we had been unable to reach agreement with respect to our migration to an *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, we filed a request for international arbitration on November 2, 2007, with the World Bank's International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010. 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. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela's actions. Separate arbitrations for contractual compensation against PDVSA are also pending before an International Chamber of Commerce (ICC) arbitration tribunal. In addition, ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador challenging a windfall profits tax and subsequent expropriation of Blocks 7 and 21. On April 24, 2012, Ecuador filed environmental and infrastructure counterclaims against Burlington relating to alleged impacts to Blocks 7 and 21. Ecuador also filed the environmental and infrastructure counterclaims relating to Blocks 7 and 21 in a separate, parallel ICSID arbitration brought by Perenco Ecuador Limited, Burlington's co-venturer and consortium operator. Perenco and Burlington each have joint liability for the counterclaims under their joint operating agreements. On December 14, 2012, the ICSID tribunal issued a decision in favor of Burlington, finding that Ecuador's seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. In February 2017, the ICSID tribunal unanimously awarded Burlington $380 million for Ecuador's unlawful expropriation and 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 impacts to Blocks 7 and 21. In December 2017, Burlington and Ecuador entered into a settlement agreement by which Ecuador agreed to pay Burlington $337 million in two installments. The first installment of $75 million was timely paid on December 1, 2017. The second installment of $262 million is to be paid by April 2018. The settlement includes an offset for the counterclaims decision, of which Burlington is entitled to a $24 million contribution from Perenco pursuant to the joint operating agreement. The ICSID arbitration between Perenco and Ecuador remains pending.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. The arbitration is being conducted under the United Nations Commission on International Trade Laws (UNCITRAL) rules using a three-person tribunal.

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. The arbitral tribunal is in the process of being constituted.

In 2017 and early 2018, cities and/or counties in California and New York have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips will be vigorously defending 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: 2018—$21 million; 2019—$7 million; 2020—$7 million; 2021—$7 million; 2022—$7 million; and 2023 and after—$74 million. Total payments under the agreements were $43 million in 2017, $42 million in 2016 and $27 million in 2015.

Note 13—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 natural gas liquids.

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 normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

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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	
	2017	2016
Assets		
Prepaid expenses and other current assets	**$ 275**	268
Other assets	**36**	44
Liabilities		
Other accruals	**282**	300
Other liabilities and deferred credits	**28**	34

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

	Millions of Dollars		
	2017	2016	2015
Sales and other operating revenues	**$ 77**	(198)	231
Other income	**-**	(1)	2
Purchased commodities	**(61)**	161	(201)

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

	Open Position Long/(Short)	
	2017	2016
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(29)**	(31)
Basis	**12**	2

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 available-for-sale 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	
	2017	2016
Assets		
Prepaid expenses and other current assets	**$ 1**	1
Other assets	**6**	-
Liabilities		
Other accruals	**-**	168
Other liabilities and deferred credits	**15**	-

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

	Millions of Dollars		
	2017	2016	2015
Foreign currency transaction (gains) losses	**$ 13**	247	(33)

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

	In Millions Notional Currency		
	2017		2016
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy other currencies(1)	USD	**-**	13
Buy U.S. dollar, sell other currencies(2)	USD	**-**	25
Buy British pound, sell other currencies(3)	GBP	**-**	1,069
Sell British pound, buy other currencies(4)	GBP	**1**	51
Sell Canadian dollar, buy U.S. dollar	CAD	**1,225**	-

(1)Primarily Canadian dollar.
(2)Primarily British pound.
(3)Primarily Canadian dollar.
(4)Primarily euro and Norwegian krone.

Financial Instruments
We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments that we currently invest include:

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.

These financial instruments appear in the “Cash and cash equivalents” line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these financial instruments are included in the “Short-term investments” line on our consolidated balance sheet.

	Millions of Dollars			
	Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments	
	2017	2016	**2017**	2016
Cash	$ **948**	623	-	-
Time deposits				
Remaining maturities from 1 to 90 days	**5,004**	2,987	**821**	39
Remaining maturities from 91 to 180 days	**-**	-	**-**	11
Commercial paper				
Remaining maturities from 1 to 90 days	**373**	-	**978**	-
Remaining maturities from 91 to 180 days	**-**	-	**74**	-
	$ 6,325	3,610	**1,873**	50

Credit Risk
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (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 and time deposits with major international banks and financial institutions.

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 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, 2017 and December 31, 2016, was $55 million and $42 million, respectively. For these instruments, no collateral was posted as of December 31, 2017, or December 31, 2016. If our credit rating had been downgraded below investment grade on December 31, 2017, we would be required to post $55 million of additional collateral, either with cash or letters of credit.

Note 14—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. At the end of the fourth quarter of 2017, our $1,899 million investment in Cenovus Energy was transferred from Level 2 to Level 1 due to the lapsing of trading restrictions. There were no other material transfers in or out of Level 1 during 2017 or 2016.

Recurring Fair Value Measurement
Financial assets and liabilities reported at fair value on a recurring basis primarily include 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. This also includes our investment in common shares of Cenovus Energy, which is valued using quotes for shares on the New York Stock Exchange. 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 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, 2017				December 31, 2016			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Investment in Cenovus Energy	**$ 1,899**	**-**	**-**	**1,899**	-	-	-	-
Commodity derivatives	**175**	**106**	**30**	**311**	194	96	22	312
Total assets	**$ 2,074**	**106**	**30**	**2,210**	194	96	22	312
Liabilities								
Commodity derivatives	**$ 158**	**111**	**41**	**310**	207	105	22	334
Total liabilities	**$ 158**	**111**	**41**	**310**	207	105	22	334

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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 offset exists.

	Millions of Dollars					
	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Gross Amounts without Right of Setoff	Net Amounts
December 31, 2017						
Assets	**$ 311**	**186**	**125**	**-**	**4**	**121**
Liabilities	**310**	**186**	**124**	**7**	**5**	**112**
December 31, 2016						
Assets	$ 312	221	91	-	5	86
Liabilities	334	221	113	12	12	89

At December 31, 2017 and December 31, 2016, 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 3 Inputs	Before-Tax Loss
Year ended December 31, 2017				
Net PP&E (held for use)				
December 31, 2017	**$ 75**	**-**	**75**	**154**
Net PP&E (held for sale)				
June 30, 2017	**2,830**	**2,830**	**-**	**3,882**
December 31, 2017	**113**	**113**	**-**	**78**
Cost and equity method investments				
June 30, 2017	**7,656**	**-**	**7,656**	**2,384**
Year ended December 31, 2016				
Net PP&E (held for use)				
March 31, 2016	$ 217	-	217	129
June 30, 2016	23	-	23	53
December 31, 2016	13	-	13	29
Net PP&E (held for sale)				
September 30, 2016	217	217	-	99
Cost and equity method investments				
December 31, 2016	90	4	86	40

Net PP&E (held for use)
Net PP&E held for use is comprised of various producing properties impaired to their individual fair values less costs to sell. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

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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.

Equity Method Investments
Certain cost and 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 2017, this included our investment in APLNG, which was written down to its fair value of $7,656 million, resulting in a before-tax-charge of $2,384 million. For additional information on APLNG, see Note 5—Investments, Loans and Long-Term Receivables. During 2016, an investment using Level 1 inputs was written down to fair value, less costs to sell, determined by its negotiated selling price. Investments using Level 3 inputs had fair values determined primarily by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount factor believed to be consistent with those used by principal market participants.

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.
- 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 6—Investment in Cenovus Energy for a discussion of the carrying value and fair value of our investment in Cenovus Energy shares.
- 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 5—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	
	2017	2016	**2017**	2016
Financial assets				
Investment in Cenovus Energy	**$ 1,899**	-	**1,899**	-
Commodity derivatives	**125**	91	**125**	91
Total loans and advances—related parties	**586**	701	**586**	701
Financial liabilities				
Total debt, excluding capital leases	**18,929**	26,423	**22,435**	29,307
Commodity derivatives	**117**	101	**117**	101

Commodity derivatives
At December 31, 2017, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $7 million of rights to reclaim cash collateral, respectively. At December 31, 2016, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $12 million of rights to reclaim cash collateral, respectively.

Note 15—Equity

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

	Shares		
	2017	2016	2015
Issued			
Beginning of year	**1,782,079,107**	1,778,226,388	1,773,583,368
Distributed under benefit plans	**3,340,068**	3,852,719	4,643,020
End of year	**1,785,419,175**	1,782,079,107	1,778,226,388
Held in Treasury			
Beginning of year	**544,809,771**	542,230,673	542,230,673
Repurchase of common stock	**63,502,263**	2,579,098	-
End of year	**608,312,034**	544,809,771	542,230,673

Preferred Stock
We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2017 or 2016.

Noncontrolling Interests
At December 31, 2017 and 2016, we had $194 million and $252 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
On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2.0 billion, with the remaining balance to be repurchased in 2019. Repurchase of shares began in November 2016, and totaled 66,081,361 shares at a cost of $3,126 million, through December 31, 2017.

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Note 16—Non-Mineral Leases

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft, computers and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 10—Debt.

At December 31, 2017, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2018	$ 278
2019	214
2020	414
2021	126
2022	307
Remaining years	209
Total	1,548
Less: income from subleases	(11)
Net minimum operating lease payments	$ 1,537

Operating lease rental expense for the years ended December 31 was:

	Millions of Dollars		
	2017	2016	2015
Total rentals	**$ 264**	537	432
Less: sublease rentals	**(20)**	(10) *	(9)
	$ 244	527	423

**Amount updated to reflect additional sublease income in 2016.*

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Note 17—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	
	2017		2016		**2017**	2016
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 3,416**	**3,445**	3,772	3,321	**286**	352
Service cost	**89**	**77**	108	76	**2**	2
Interest cost	**118**	**103**	133	120	**9**	13
Plan participant contributions	**-**	**2**	-	3	**23**	24
Plan amendments	**-**	**-**	-	-	**-**	(27)
Actuarial (gain) loss	**244**	**52**	247	466	**12**	(14)
Benefits paid	**(631)**	**(117)**	(872)	(148)	**(68)**	(68)
Curtailment	**-**	**-**	14	10	**-**	3
Settlement	**-**	**-**	-	(46)	**-**	-
Recognition of termination benefits	**-**	**-**	14	1	**-**	-
Foreign currency exchange rate change	**-**	**283**	-	(358)	**1**	1
Benefit obligation at December 31*	**$ 3,236**	3,845	3,416	3,445	265	286
**Accumulated benefit obligation portion of above at December 31:*	*$ 3,076*	*3,404*	*3,246*	*3,067*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 2,081**	**3,068**	2,606	3,063	**-**	-
Actual return on plan assets	**336**	**313**	133	397	**-**	-
Company contributions	**755**	**114**	214	125	**45**	44
Plan participant contributions	**-**	**2**	-	3	**23**	24
Benefits paid	**(631)**	**(117)**	(872)	(148)	**(68)**	(68)
Foreign currency exchange rate change	**-**	**267**	-	(372)	**-**	-
Fair value of plan assets at December 31	**$ 2,541**	3,647	2,081	3,068	-	-
Funded Status	**$ (695)**	**(198)**	(1,335)	(377)	**(265)**	(286)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2017		2016		**2017**	2016
	U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	**$ -**	**205**	-	164	**-**	-
Current liabilities	**(38)**	**(4)**	(101)	(7)	**(45)**	(44)
Noncurrent liabilities	**(657)**	**(399)**	(1,234)	(534)	**(220)**	(242)
Total recognized	**$ (695)**	**(198)**	(1,335)	(377)	**(265)**	(286)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**3.55%**	**2.80**	3.95	3.00	**3.30**	3.60
Rate of compensation increase	**4.00**	**3.75**	4.00	3.85	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**3.80%**	**3.00**	3.90	3.95	**3.60**	3.75
Expected return on plan assets	**6.55**	**5.05**	7.00	5.45	**-**	-
Rate of compensation increase	**4.00**	**3.85**	4.00	4.05	**-**	-

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:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2017		2016		**2017**	2016
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial (gain) loss	**$ 588**	**358**	748	479	**(12)**	(27)
Unrecognized prior service cost (credit)	**-**	**(16)**	4	(20)	**(249)**	(285)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2017		2016		**2017**	2016
	U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)						
Net gain (loss) arising during the period	**$ (40)**	**71**	(263)	(232)	**(12)**	14
Amortization of (gain) loss included in income (loss)*	**200**	**50**	288	26	**(3)**	(5)
Net change during the period	**$ 160**	**121**	25	(206)	**(15)**	9
Prior service credit (cost) arising during the period	**$ -**	**2**	-	(4)	**-**	27
Amortization of prior service cost (credit) included in income (loss)	**4**	**(6)**	5	(6)	**(36)**	(34)
Net change during the period	**$ 4**	**(4)**	5	(10)	**(36)**	(7)

**Includes settlement losses recognized in 2017 and 2016.*

During the year ended December 31, 2016, there was an amendment to the U.S. other postretirement benefit plan. The benefit obligation decreased by $27 million for changes in the plan made to post-65 retiree medical benefits related to updated cost sharing assumption changes for retirees. The $27 million decrease in the benefit obligation resulted in a corresponding increase in other comprehensive income.

Included in accumulated other comprehensive loss at December 31, 2017, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2018:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int'l.	
Unrecognized net actuarial (gain) loss	$ 59	36	(1)
Unrecognized prior service credit	-	(5)	(34)

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 $5,634 million, $5,226 million, and $5,113 million, respectively, at December 31, 2017, and $5,498 million, $5,145 million, and $4,208 million, respectively, at December 31, 2016.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $578 million and $503 million, respectively, at December 31, 2017, and were $586 million and $496 million, respectively, at December 31, 2016.

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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		
	2017		2016		2015		**2017**	2016	2015
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 89**	**77**	108	76	138	124	**2**	2	4
Interest cost	**118**	**103**	133	120	161	135	**9**	13	22
Expected return on plan assets	**(132)**	**(158)**	(149)	(147)	(201)	(164)	**-**	-	-
Amortization of prior service cost (credit)	**4**	**(6)**	5	(6)	6	(7)	**(36)**	(34)	(17)
Recognized net actuarial loss (gain)	**69**	**50**	86	26	115	82	**(3)**	(2)	2
Settlements	**131**	**-**	202	-	197	7	**-**	-	-
Curtailment (gain) loss	**-**	**-**	14	-	35	(4)	**-**	1	2
Net periodic benefit cost	**$ 279**	**66**	399	69	451	173	**(28)**	(20)	13

We recognized pension settlement losses of $131 million in 2017, $202 million in 2016 and $204 million in 2015 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

As part of the 2016 and 2015 restructuring programs, we concluded that actions taken during those years resulted in a significant reduction of future services of active employees primarily in the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as curtailment losses of $15 million and $33 million during the years ended December 31, 2016 and 2015, respectively.

Also as part of the 2016 and 2015 restructuring programs in the U.S. and Europe, we recognized expense for special termination benefits of $15 million during the year ended December 31, 2016, consisting of $14 million in the U.S. and $1 million in Europe, and $124 million during the year ended December 31, 2015, consisting of $46 million in the U.S. and $78 million in Europe. Approximately 62 percent of the 2015 Europe amount was recovered from joint venture partners.

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 6.25 percent in 2018 that declines to 5 percent by 2023. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes an ultimate health care cost trend rate of 5 percent achieved in 2018. 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 43 percent equity securities, 50 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, 2017 and 2016.

- 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, 2017, the participating interest in the annuity contract was valued at $99 million and consisted of $265 million in debt securities, less $166 million for the accumulated benefit obligation covered by the contract. At December 31, 2016, the participating interest in the annuity contract was valued at $121 million and consisted of $288 million in debt securities, less $167 million for the accumulated benefit obligation covered by the contract. The net change from 2016 to 2017 is due to a decrease in the fair value of the underlying investments of $23 million offset by a decrease in the present value of the contract obligation of $1 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.

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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
2017								
Equity Securities								
U.S.	$ **161**	**-**	**14**	**175**	**440**	**-**	**-**	**440**
International	**178**	**-**	**-**	**178**	**315**	**-**	**-**	**315**
Common/collective trusts	**-**	**-**	**-**	**-**	**-**	**183**	**-**	**183**
Mutual funds	**146**	**-**	**-**	**146**	**292**	**165**	**-**	**457**
Debt Securities								
Government	**-**	**-**	**-**	**-**	**902**	**-**	**-**	**902**
Corporate	**-**	**2**	**-**	**2**	**-**	**-**	**-**	**-**
Common/collective trusts	**-**	**-**	**-**	**-**	**-**	**648**	**-**	**648**
Mutual funds	**-**	**-**	**-**	**-**	**144**	**-**	**-**	**144**
Cash and cash equivalents	**-**	**-**	**-**	**-**	**111**	**-**	**-**	**111**
Time deposits	**-**	**-**	**-**	**-**	**3**	**-**	**-**	**3**
Derivatives	**-**	**-**	**-**	**-**	**5**	**-**	**-**	**5**
Real estate	-	-	-	-	-	-	**123**	**123**
Total in fair value hierarchy	$ **485**	**2**	**14**	**501**	**2,212**	**996**	**123**	**3,331**
Investments measured at net asset value*								
Equity Securities								
Common/collective trusts	$ **-**	**-**	**-**	**805**	**-**	**-**	**-**	**-**
Debt Securities								
Corporate	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**172**
Agency and mortgage-backed securities	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**15**
Common/collective trusts	**-**	**-**	**-**	**1,042**	**-**	**-**	**-**	**-**
Cash and cash equivalents	**-**	**-**	**-**	**17**	**-**	**-**	**-**	**24**
Real estate	**-**	**-**	**-**	**74**	**-**	**-**	**-**	**94**
Total**	$ **485**	**2**	**14**	**2,439**	**2,212**	**996**	**123**	**3,636**

**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 value of $99 million and net receivables related to security transactions of $14 million.*

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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
2016								
Equity Securities								
U.S.	$ 632	-	14	646	628	-	-	628
International	342	-	-	342	428	-	-	428
Common/collective trusts	-	-	-	-	-	156	-	156
Mutual funds	62	-	-	62	268	139	-	407
Debt Securities								
Government	-	38	-	38	470	-	-	470
Corporate	-	54	3	57	-	-	-	-
Common/collective trusts	-	-	-	-	-	385	-	385
Mutual funds	-	-	-	-	137	-	-	137
Cash and cash equivalents	-	-	-	-	48	-	-	48
Derivatives	-	-	-	-	18	-	-	18
Real estate	-	-	-	-	-	-	111	111
Total in fair value hierarchy	$ 1,036	92	17	1,145	1,997	680	111	2,788
Investments measured at net asset value*								
Equity Securities								
Common/collective trusts	$ -	-	-	410	-	-	-	-
Debt Securities								
Corporate	-	-	-	-	-	-	-	155
Agency and mortgage-backed securities	-	-	-	-	-	-	-	27
Common/collective trusts	-	-	-	312	-	-	-	-
Cash and cash equivalents	-	-	-	36	-	-	-	11
Real estate	-	-	-	69	-	-	-	76
Total**	$ 1,036	92	17	1,972	1,997	680	111	3,057

**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 value of $121 million and net payables related to security transactions of $1 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 2018, we expect to contribute approximately $80 million to our domestic nonqualified pension and postretirement benefit plans and $130 million to our international qualified and nonqualified pension and postretirement benefit plans.

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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.	
2018	$ 383	122	40
2019	302	141	37
2020	290	135	34
2021	286	144	31
2022	291	144	28
2023–2027	1,247	780	91

Severance Accrual
As a result of selling our 50 percent nonoperated interest in the FCCL Partnership and the majority of our western Canada gas assets, as well as our interest in the San Juan Basin, a reduction in our overall employee workforce occurred during 2017. Severance accruals of $65 million were recorded in 2017. The following table summarizes our severance accrual activity for the year ended December 31, 2017:

	Millions of Dollars
Balance at December 31, 2016	$ 80
Accruals	**65**
Benefit payments	**(93)**
Foreign currency translation adjustments	**1**
Balance at December 31, 2017	**$ 53**

Of the remaining balance at December 31, 2017, $30 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 34 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. Company contributions charged to expense for the CPSP and predecessor plans were $51 million in 2017, $58 million in 2016, and $109 million in 2015.

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 $35 million in 2017, $44 million in 2016, and $55 million in 2015.

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 loss and the associated tax benefit for the years ended December 31 were as follows:

	Millions of Dollars		
	2017	2016	2015
Compensation cost	**$ 227**	272	362
Tax benefit	**76**	92	123

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 market price 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.

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

	2017	2016	2015
Assumptions used			
Risk-free interest rate	**2.24 %**	1.55	1.79
Dividend yield	**4.00 %**	4.00	4.00
Volatility factor	**28.12 %**	26.80	23.32
Expected life (years)	**6.39**	6.37	5.79

There were no ranges in the assumptions used to determine the fair market values of our options granted over the past three years.

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 2015 through 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.

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The following summarizes our stock option activity for the year ended December 31, 2017:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2016	23,712,112	$ 52.14		$ 128
Granted	**2,670,200**	**49.76**	**$ 9.18**	
Exercised	**(360,396)**	**37.24**		**4**
Forfeited	**(50,696)**	**48.55**		
Expired or cancelled	**(1,248,417)**	**50.61**		
Outstanding at December 31, 2017	**24,722,803**	**$ 52.18**		**$ 177**
Vested at December 31, 2017	**23,424,010**	**$ 52.52**		**$ 162**
Exercisable at December 31, 2017	**18,074,088**	**$ 54.34**		**$ 101**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2017, was 5.52 years, 5.36 years and 4.50 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2016 and 2015 was $5.39 and $9.54, respectively. The aggregate intrinsic value of options exercised was zero in 2016 and $10 million in 2015.

During 2017, we received $13 million in cash and realized a tax benefit of $12 million from the exercise of options. At December 31, 2017, the remaining unrecognized compensation expense from unvested options was $5 million, which will be recognized over a weighted-average period of 1.33 years, the longest period being 2.12 years.

Beginning in 2018, stock option grants will be discontinued and replaced with three-year, time-vested restricted stock units which will be cash-settled.

Stock Unit Program—Generally, restricted stock units are granted annually under the provisions of the Plan. Restricted stock units granted prior to 2013 generally vest ratably in three equal annual installments beginning on the third anniversary of the grant date. Beginning in 2013, restricted stock units granted will vest in an aggregate installment on the third anniversary of the grant date. In addition, beginning in 2012, 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. Upon vesting, the 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 unit activity for the year ended December 31, 2017:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2016	8,507,504	$ 48.65	
Granted	**3,011,903**	**48.77**	
Forfeited	**(372,871)**	**45.99**	
Issued	**(3,319,684)**		**$ 159**
Outstanding at December 31, 2017	**7,826,852**	**$ 45.75**	
Not Vested at December 31, 2017	**5,396,027**	**$ 45.58**	

At December 31, 2017, the remaining unrecognized compensation cost from the unvested units was $93 million, which will be recognized over a weighted-average period of 1.67 years, the longest period being 2.75 years. The weighted-average grant date fair value of stock unit awards granted during 2016 and 2015 was $32.15 and $65.40, respectively. The total fair value of stock units issued during 2016 and 2015 was $191 million and $316 million, respectively.

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.

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The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2017:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2016	3,889,524	$ 51.93	
Granted	**30,953**	**49.76**	
Issued	**(1,167,012)**		**$ 57**
Outstanding at December 31, 2017	**2,753,465**	**$ 50.79**	
Not Vested at December 31, 2017	**67,083**	**$ 48.17**	

At December 31, 2017, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was $1 million, which will be recognized over a weighted-average period of 2.00 years, the longest period being 3.00 years. The weighted-average grant date fair value of stock-settled PSUs granted during 2016 and 2015 was $33.13 and $69.25, respectively. The total fair value of stock-settled PSUs issued during 2016 and 2015 was $17 million and $25 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. 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.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2017:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2016	1,274,762	$ 50.39	
Granted	**456,909**	**49.76**	
Settled	**(517,138)**		**$ 24**
Outstanding at December 31, 2017	**1,214,533**	**$ 55.19**	
Not Vested at December 31, 2017	**122,228**	**$ 55.19**	

At December 31, 2017, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $2 million, which will be recognized over a weighted-average period of 1.64 years, the longest period being 2.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2016 and 2015 was $33.13 and $69.25, respectively. The total fair value of cash-settled performance share awards settled during 2016 and 2015 was $31 million and $6 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, 2017:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2016	1,317,964	$ 33.16	
Granted	**87,980**	**48.87**	
Cancelled	**(24,486)**	**21.37**	
Issued	**(80,418)**		**$ 4**
Outstanding at December 31, 2017	**1,301,040**	**$ 32.66**	
Not Vested at December 31, 2017	**-**		

At December 31, 2017, 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 2016 and 2015 was $40.36 and $58.66, respectively. The total fair value of awards issued during 2016 and 2015 was $2 million and $3 million, respectively.

Note 18—Income Taxes

Income tax benefits included in net loss were:

		Millions of Dollars		
		2017	2016	2015
Income Taxes				
Federal				
Current	$	**79**	(9)	(718)
Deferred		**(3,046)**	(1,634)	(1,443)
Foreign				
Current		**1,729**	393	745
Deferred		**(510)**	(519)	(1,315)
State and local				
Current		**51**	(135)	8
Deferred		**(125)**	(67)	(145)
	$	**(1,822)**	(1,971)	(2,868)

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	
		2017	2016
Deferred Tax Liabilities			
PP&E and intangibles	$	**9,692**	15,099
Investments in joint ventures		**-**	933
Inventory		**61**	36
Deferred state income tax		**178**	203
Other		**464**	486
Total deferred tax liabilities		**10,395**	16,757
Deferred Tax Assets			
Benefit plan accruals		**786**	1,280
Asset retirement obligations and accrued environmental costs		**3,060**	3,514
Investments in joint ventures		**57**	-
Other financial accruals and deferrals		**166**	317
Loss and credit carryforwards		**2,310**	3,522
Other		**152**	250
Total deferred tax assets		**6,531**	8,883
Less: valuation allowance		**(1,254)**	(675)
Net deferred tax assets		**5,277**	8,208
Net deferred tax liabilities	$	**5,118**	8,549

At December 31, 2017, noncurrent assets and liabilities included deferred taxes of $164 million and $5,282 million, respectively. At December 31, 2016, noncurrent assets and liabilities included deferred taxes of $400 million and $8,949 million, respectively.

At December 31, 2017, the components of our loss and credit carryforwards before and after consideration of the applicable valuation allowances are:

	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	$ 856	567	2025-2027
U.S. general business credits	227	227	2036-2037
State net operating losses and tax credits	420	-	
Foreign net operating losses and tax credits	807	786	Post 2025
	$ 2,310	1,580	

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2017, valuation allowances increased a total of $579 million. This increase primarily relates to the expected realization of certain deferred tax assets, including foreign tax credits; U.S. tax basis associated with foreign assets; and state net operating losses and tax credits not expected to be realized. 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.

At December 31, 2017, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,600 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 that would be payable on this income if distributed is approximately $130 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2017, 2016 and 2015:

	Millions of Dollars		
	2017	2016	2015
Balance at January 1	**$ 381**	459	442
Additions based on tax positions related to the current year	**612**	32	54
Additions for tax positions of prior years	**109**	19	4
Reductions for tax positions of prior years	**(129)**	(118)	(37)
Settlements	**(5)**	(9)	(4)
Lapse of statute	**(86)**	(2)	-
Balance at December 31	**$ 882**	381	459

Included in the balance of unrecognized tax benefits for 2017, 2016 and 2015 were $882 million, $359 million and $354 million, respectively, which, if recognized, would impact our effective tax rate. 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.

At December 31, 2017, 2016 and 2015, accrued liabilities for interest and penalties totaled $54 million, $54 million and $79 million, respectively, net of accrued income taxes. Interest and penalties resulted in no impact to earnings in 2017, a benefit to earnings of $18 million in 2016, and a reduction to earnings of $11 million in 2015.

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We and our subsidiaries 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: United Kingdom (2014), Canada (2009), United States (2010) and Norway (2016). 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. As a consequence, 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)		
	2017	2016	2015	**2017**	2016	2015
Loss before income taxes						
United States	**$ (5,250)**	(4,410)	(4,150)	**200.8 %**	79.7	57.3
Foreign	**2,635**	(1,120)	(3,089)	**(100.8)**	20.3	42.7
	$ (2,615)	(5,530)	(7,239)	**100.0 %**	100.0	100.0
Federal statutory income tax	**$ (915)**	(1,936)	(2,534)	**35.0 %**	35.0	35.0
Non-U.S. effective tax rates	**625**	361	301	**(23.9)**	(6.5)	(4.2)
Impact of U.S. tax legislation	**(852)**	-	-	**32.6**	-	-
Canada disposition	**(1,277)**	-	-	**48.8**	-	-
Recovery of outside basis	**(962)**	(60)	(491)	**36.8**	1.1	6.8
Adjustment to tax reserves	**881**	55	42	**(33.7)**	(1.0)	(0.6)
APLNG impairment	**834**	-	525	**(31.9)**	-	(7.3)
State income tax	**(84)**	(122)	(85)	**3.2**	2.2	1.2
Enhanced oil recovery credit	**(68)**	(62)	-	**2.6**	1.1	-
U.K. rate change	**-**	(161)	(555)	**-**	2.9	7.7
Canada rate change	**-**	-	129	**-**	-	(1.8)
U.S. fair value election	**-**	-	(185)	**-**	-	2.6
Other	**(4)**	(46)	(15)	**0.2**	0.8	0.2
	$ (1,822)	(1,971)	(2,868)	**69.7 %**	35.6	39.6

The increase in the effective tax rate for 2017 was primarily due to the impact of the Tax Cuts and Jobs Act (Tax Legislation) and the impact of the Canada disposition, partially offset by the impact of the APLNG impairment and our mix of income among taxing jurisdictions.

The Tax Legislation, enacted on December 22, 2017, reduces the U.S. federal corporate tax rate from 35 percent to 21 percent, requires companies to pay a one-time transition tax on earnings of certain foreign subsidiaries that were previously tax deferred and creates new taxes on certain foreign-sourced earnings. At December 31, 2017, we have not completed our accounting for the tax effects of enactment of the Tax Legislation; however, as described below, we have made a reasonable estimate of the effects on our existing deferred tax balances and the one-time transition tax and recorded a provisional tax benefit of $852 million.

Provisional Amount—Deferred tax assets and liabilities
In the fourth quarter of 2017, we remeasured certain U.S. deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21 percent. However, we are still analyzing certain aspects of the Tax Legislation and refining our calculations, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. The provisional amount recorded related to the remeasurement of our U.S. deferred tax balance was a tax benefit of $908 million.

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Provisional Amount—Foreign tax effects
The one-time transition tax is based on our total post-1986 earnings and profits which we have previously deferred from U.S. income taxes. We reasonably estimate that we will not incur a one-time transition tax. This assumption may change when we finalize the calculation of post-1986 foreign earnings and profits, previously deferred from U.S. federal taxation, and finalize the amounts held in cash or other specified assets. As a result of the Tax Legislation, we have 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.

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 4—Assets Held for Sale, Sold or Acquired 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 5—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment.

The decrease in the effective tax rate for 2016 was primarily due to our mix of income among taxing jurisdictions, reduced net tax benefit from the tax law changes discussed below, and the absence of a tax benefit associated with electing the fair market value method of apportioning interest expense for prior years.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, we recorded a $161 million net tax benefit related to the remeasurement of our U.K. deferred tax balance in 2016.

In the United Kingdom, legislation was enacted on March 26, 2015, to decrease the overall U.K. upstream corporation tax rate from 62 percent to 50 percent effective January 1, 2015. As a result, we recorded a $555 million net tax benefit related to the remeasurement of our U.K. deferred tax balance in 2015.

In Canada, legislation was enacted on June 29, 2015, to increase the overall Canadian corporation tax rate from 25 percent to 27 percent effective July 1, 2015. As a result, we recorded a $129 million net tax expense related to the remeasurement of our Canadian deferred tax balance in 2015.

In December 2015, we filed refund claims for prior years electing the fair market value method of apportioning interest in the United States. As a result, we recorded a $185 million tax benefit associated with these refund claims in 2015.

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 2017, 2016 and 2015 the amount of the tax benefit was $962 million, $60 million and $491 million, respectively.

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Note 19—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, 2014	$ (1,261)	-	(641)	(1,902)
Other comprehensive income (loss)	818	-	(5,163)	(4,345)
December 31, 2015	(443)	-	(5,804)	(6,247)
Other comprehensive income (loss)	(104)	-	158	54
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)**

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	
	2017	2016
Defined Benefit Plans	**$ 135**	179
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	*$ 74*	*95*

See Note 17—Employee Benefit Plans, for additional information.

Note 20—Cash Flow Information

	Millions of Dollars		
	2017	2016	2015
Noncash Investing Activities			
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	**$ (37)**	(1,017)	402
Cash Payments (Receipts)			
Interest	**$ 1,163**	1,151	920
Income taxes	**1,168**	(318)*	523 *
Net Sales (Purchases) of Short-Term Investments			
Short-term investments purchased	**$ (6,617)**	(1,753)	-
Short-term investments sold	**4,827**	1,702	-
	$ (1,790)	(51)	-

**Net of $585 million and $642 million in 2016 and 2015, respectively, related to refunds received from the Internal Revenue Service.*

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Note 21—Other Financial Information

	Millions of Dollars		
	2017	2016	2015
Interest and Debt Expense			
Incurred			
Debt	$ **1,114**	1,279	1,130
Other	**103**	123	84
	1,217	1,402	1,214
Capitalized	**(119)**	(157)	(294)
Expensed	$ **1,098**	1,245	920
Other Income			
Interest income	$ **112**	57	45
Other, net	**417**	198	80
	$ **529**	255	125
Research and Development Expenditures—expensed	$ **100**	116	222
Shipping and Handling Costs*	$ **1,058**	1,139	1,181

**Amounts included in production and operating expenses.*

	Millions of Dollars		
	2017	2016	2015
Foreign Currency Transaction (Gains) Losses—after-tax			
Alaska	$ **-**	-	-
Lower 48	**-**	-	-
Canada	**3**	1	-
Europe and North Africa	**7**	(7)	(22)
Asia Pacific and Middle East	**23**	(9)	(78)
Other International	**1**	7	(9)
Corporate and Other	**(3)**	(18)	45
	$ **31**	(26)	(64)

	Millions of Dollars	
	2017	2016
Properties, Plants and Equipment		
Proved properties	**$ 102,044**	119,970
Unproved properties	**4,491**	5,150
Other	**3,896**	6,286
Gross properties, plants and equipment	**110,431**	131,406
Less: Accumulated depreciation, depletion and amortization	**(64,748)**	(73,075)
Net properties, plants and equipment	**$ 45,683**	58,331

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Note 22—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		
	2017	2016	2015
Operating revenues and other income	**$ 107**	133	118
Purchases	**99**	101	97
Operating expenses and selling, general and administrative expenses	**59**	63	62
Net interest (income) expense*	**(13)**	(12)	(9)

**We paid interest to, or received interest from, various affiliates. See Note 5—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 5—Investments, Loans and Long-Term Receivables, for additional information.

Note 23—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids 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.

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Analysis of Results by Operating Segment

	Millions of Dollars		
	2017	2016	2015
Sales and Other Operating Revenues			
Alaska	**$ 4,224**	3,681	4,351
Lower 48	**12,968**	10,719	11,976
Intersegment eliminations	**(4)**	(17)	(63)
Lower 48	**12,964**	10,702	11,913
Canada	**3,178**	2,192	2,454
Intersegment eliminations	**(559)**	(218)	(318)
Canada	**2,619**	1,974	2,136
Europe and North Africa	**5,181**	3,462	6,110
Intersegment eliminations	**-**	-	(4)
Europe and North Africa	**5,181**	3,462	6,106
Asia Pacific and Middle East	**4,014**	3,705	4,746
Intersegment eliminations	**-**	-	(1)
Asia Pacific and Middle East	**4,014**	3,705	4,745
Other International	**-**	-	1
Corporate and Other	**104**	169	312
Consolidated sales and other operating revenues	**$ 29,106**	23,693	29,564
Depreciation, Depletion, Amortization and Impairments			
Alaska	**$ 1,026**	868	690
Lower 48	**6,693**	4,358	4,227
Canada	**461**	975	788
Europe and North Africa	**1,313**	1,253	2,565
Asia Pacific and Middle East	**3,819**	1,606	2,981
Other International	**-**	1	-
Corporate and Other	**134**	140	107
Consolidated depreciation, depletion, amortization and impairments	**$ 13,446**	9,201	11,358

In 2017, sales by our Lower 48, Alaska and Canada segments to a certain refining company accounted for approximately $3 billion or 11 percent of our total consolidated sales and other operating revenues.

	Millions of Dollars		
	2017	2016	2015
Equity in Earnings of Affiliates			
Alaska	**$ 7**	9	4
Lower 48	**5**	(6)	(5)
Canada	**197**	89	78
Europe and North Africa	**10**	22	23
Asia Pacific and Middle East	**553**	(51)	550
Other International	**-**	-	8
Corporate and Other	**-**	(11)	(3)
Consolidated equity in earnings of affiliates	**$ 772**	52	655
Income Taxes			
Alaska	**$ (689)**	(59)	(71)
Lower 48	**(2,453)**	(1,328)	(1,119)
Canada	**(616)**	(383)	(223)
Europe and North Africa	**1,165**	(46)	(854)
Asia Pacific and Middle East	**351**	306	467
Other International	**21**	(40)	(456)
Corporate and Other	**399**	(421)	(612)
Consolidated income taxes	**$ (1,822)**	(1,971)	(2,868)
Net Income (Loss) Attributable to ConocoPhillips			
Alaska	**$ 1,466**	319	4
Lower 48	**(2,371)**	(2,257)	(1,932)
Canada	**2,564**	(935)	(1,044)
Europe and North Africa	**553**	394	409
Asia Pacific and Middle East	**(1,098)**	209	(463)
Other International	**167**	(16)	(593)
Corporate and Other	**(2,136)**	(1,329)	(809)
Consolidated net loss attributable to ConocoPhillips	**$ (855)**	(3,615)	(4,428)
Investments In and Advances To Affiliates			
Alaska	**$ 56**	58	61
Lower 48	**402**	426	455
Canada	**-**	8,784	8,165
Europe and North Africa	**55**	62	70
Asia Pacific and Middle East	**9,077**	11,611	11,780
Other International	**-**	-	-
Corporate and Other	**-**	4	15
Consolidated investments in and advances to affiliates	**$ 9,590**	20,945	20,546

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	Millions of Dollars		
	2017	2016	2015
Total Assets			
Alaska	**$ 12,108**	12,314	12,555
Lower 48	**14,632**	22,673	26,932
Canada	**6,214**	17,548	17,221
Europe and North Africa	**11,870**	11,727	13,703
Asia Pacific and Middle East	**16,985**	20,451	22,318
Other International	**97**	97	282
Corporate and Other	**11,456**	4,962	4,473
Consolidated total assets	**$ 73,362**	89,772	97,484
Capital Expenditures and Investments			
Alaska	**$ 815**	883	1,352
Lower 48	**2,136**	1,262	3,765
Canada	**202**	698	1,255
Europe and North Africa	**872**	1,020	1,573
Asia Pacific and Middle East	**482**	838	1,812
Other International	**21**	104	173
Corporate and Other	**63**	64	120
Consolidated capital expenditures and investments	**$ 4,591**	4,869	10,050
Interest Income and Expense			
Interest income			
Corporate	**$ 101**	47	36
Lower 48	**-**	-	-
Europe and North Africa	**2**	2	2
Asia Pacific and Middle East	**9**	8	6
Other International	**-**	-	1
Interest and debt expense			
Corporate	**$ 1,098**	1,245	920
Sales and Other Operating Revenues by Product			
Crude oil	**$ 13,260**	10,801	12,830
Natural gas	**10,773**	9,401	11,888
Natural gas liquids	**1,102**	837	952
Other*	**3,971**	2,654	3,894
Consolidated sales and other operating revenues by product	**$ 29,106**	23,693	29,564

**Includes LNG and bitumen.*

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Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues(1)			Long-Lived Assets(2)		
	2017	2016	2015	**2017**	2016	2015
United States	**$ 17,204**	14,400	16,284	**23,623**	32,949	37,445
Australia(3)	**1,448**	1,353	2,127	**9,657**	12,259	12,788
Canada	**2,619**	1,974	2,136	**5,613**	16,846	16,766
China	**712**	551	782	**1,275**	1,372	1,647
Indonesia	**757**	938	1,165	**758**	856	1,191
Malaysia	**1,103**	735	598	**2,736**	3,323	3,599
Norway	**2,348**	1,645	2,107	**6,154**	6,228	6,933
United Kingdom	**2,248**	1,816	4,005	**3,335**	3,209	4,154
Other foreign countries	**667**	281	360	**2,122**	2,234	2,469
Worldwide consolidated	**$ 29,106**	23,693	29,564	**55,273**	79,276	86,992

(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 investments in and advances to affiliated companies.
(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.

Note 24—New Accounting Standards

In May 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-09, “Revenue from Contracts with Customers” (ASU No. 2014-09), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. This ASU supersedes the revenue recognition requirements in FASB ASC Topic 605, “Revenue Recognition,” and most industry-specific guidance. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts.

In August 2015, the FASB issued ASU No. 2015-14, “Deferral of the Effective Date,” which defers the effective date of ASU No. 2014-09. The ASU is now effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for interim and annual periods beginning after December 15, 2016. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach.

ASU No. 2014-09 was amended in March 2016 by the provisions of ASU No. 2016-08, “Principal versus Agent Considerations (Reporting Revenue Gross versus Net),” in April 2016 by the provisions of ASU No. 2016-10, “Identifying Performance Obligations and Licensing,” in May 2016 by the provisions of ASU No. 2016-12, “Narrow-Scope Improvements and Practical Expedients,” and in December 2016 by the provisions of ASU No. 2016-20, “Technical Corrections and Improvements to Topic 606, Revenue From Contracts With Customers.”

We will adopt the provisions of ASU No. 2014-09, as amended, with effect from January 1, 2018, and have elected not to early adopt the standard. We will adopt the new standard using the modified retrospective approach which we will apply only to contracts within the scope of the standard that are not complete at the date of initial application. Under this approach, we will apply the guidance retrospectively only to the most current period presented in the financial statements. The impact to our financial statements is immaterial but will include a cumulative effect reduction of $220 million to retained earnings from initially applying the new revenue standard relating to licensing revenues previously recognized. Under the new revenue standard licensing revenue will be recognized when the customer can utilize and benefit from their right to use the license.

In January 2016, the FASB issued ASU No. 2016-01, “Recognition and Measurement of Financial Assets and Financial Liabilities” (ASU No. 2016-01), to meet its objective of providing more decision-useful information about financial instruments. The ASU, among other things, requires entities to record the changes in fair value of equity investments, other than investments accounted for using the equity method, within net income. Under this ASU, entities will no longer be able to recognize unrealized holding gains and losses on available-for-sale securities in other comprehensive income. The ASU also requires additional disclosures relating to fair value measurement categories for financial assets and liabilities and eliminates certain disclosure requirements related to financial instruments measured at amortized cost. ASU No. 2016-01 is effective for interim and annual periods beginning after December 15, 2017, and the ASU should be adopted using a cumulative-effect adjustment to retained earnings as of the date of adoption.

Upon adoption of the standard, we will make a cumulative-effect adjustment to reclassify the accumulated unrealized holding gains and losses of $58 million related to our investment in Cenovus Energy from other comprehensive income to retained earnings. From January 1, 2018, we will begin reporting the changes in the fair value of our investment within net income. For additional information on our investment in Cenovus Energy, see Note 6—Investment in Cenovus Energy, Note 14—Fair Value Measurement, and Note 19 —Accumulated Other Comprehensive Loss.

In February 2016, the FASB issued ASU No. 2016-02, “Leases” (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, “Leases,” and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. In January 2018, ASU No. 2016-02 was amended by the provisions of ASU No. 2018-01, “Land Easement Practical Expedient for Transition to Topic 842.” We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, and continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. We also continue to monitor proposals issued by the FASB to clarify the ASU and certain industry implementation issues. While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures.

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, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (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.

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 production sharing contracts (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, 2017, approximately 8 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 5 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of Russia, which we exited in 2015.

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.

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 2017, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2017, 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, 2017, 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 United States 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.

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Proved Reserves

Years Ended December 31	Crude Oil Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
End of 2014	1,063	676	1,739	24	411	227	204	-	2,605
Revisions	(115)	(69)	(184)	-	(21)	(29)	-	-	(234)
Improved recovery	4	4	8	1	-	31	-	-	40
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	20	57	77	1	-	7	-	-	85
Production	(57)	(78)	(135)	(4)	(44)	(33)	-	-	(216)
Sales	-	(2)	(2)	(8)	-	-	-	-	(10)
End of 2015	915	588	1,503	14	346	203	204	-	2,270
Revisions	(57)	(93)	(150)	3	-	6	-	-	(141)
Improved recovery	6	3	9	-	-	7	-	-	16
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	33	79	112	-	-	7	-	-	119
Production	(60)	(71)	(131)	(3)	(43)	(35)	(1)	-	(213)
Sales	-	-	-	(1)	-	(3)	-	-	(4)
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
Equity affiliates									
End of 2014	-	-	-	-	-	98	-	5	103
Revisions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(1)	(6)
Sales	-	-	-	-	-	-	-	(4)	(4)
End of 2015	-	-	-	-	-	93	-	-	93
Revisions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	-	(5)
Sales	-	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	88	-	-	88
Revisions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-

Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	-	(5)
Sales	-	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	83	-	-	83
Total company									
End of 2014	1,063	676	1,739	24	411	325	204	5	2,708
End of 2015	915	588	1,503	14	346	296	204	-	2,363
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

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Years Ended December 31	Crude Oil Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
End of 2014	950	313	1,263	23	237	142	199	-	1,864
End of 2015	819	283	1,102	13	200	139	204	-	1,658
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
Equity affiliates									
End of 2014	-	-	-	-	-	98	-	5	103
End of 2015	-	-	-	-	-	93	-	-	93
End of 2016	-	-	-	-	-	88	-	-	88
End of 2017	-	-	-	-	-	83	-	-	83
Undeveloped									
Consolidated operations									
End of 2014	113	363	476	1	174	85	5	-	741
End of 2015	96	305	401	1	146	64	-	-	612
End of 2016	90	250	340	-	119	79	-	-	538
End of 2017	109	392	501	-	106	64	-	-	671
Equity affiliates									
End of 2014	-	-	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions in Alaska, Lower 48, Europe and Asia Pacific/Middle East were primarily due to higher prices. In 2016, revisions in Lower 48 and Alaska were primarily due to lower prices. In 2015, revisions in Alaska, Lower 48 and Asia Pacific/Middle East were primarily due to lower prices.
- *Extensions and discoveries*: In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken. In 2016, extensions and discoveries in Alaska were primarily due to drilling success in the Western North Slope, and extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.
- *Sales*: In 2017, Canada sales were due to the disposition of a majority of our western Canada assets.

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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 2014	120	440	560	65	24	13	662
Revisions	(1)	(84)	(85)	(10)	(1)	(2)	(98)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	10	10	2	-	-	12
Production	(5)	(36)	(41)	(9)	(3)	(3)	(56)
Sales	-	(9)	(9)	(3)	-	-	(12)
End of 2015	114	321	435	45	20	8	508
Revisions	(3)	(29)	(32)	9	2	-	(21)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	18	18	2	-	-	20
Production	(4)	(32)	(36)	(8)	(3)	(3)	(50)
Sales	-	-	-	-	-	-	-
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
Equity affiliates							
End of 2014	-	-	-	-	-	53	53
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	50	50
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	47	47
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(2)	(2)
Sales	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	45	45
Total company							
End of 2014	120	440	560	65	24	66	715
End of 2015	114	321	435	45	20	58	558
End of 2016	107	278	385	48	19	52	504

End of 2017	106	224	330	1	18	50	399

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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 2014	120	337	457	57	18	11	543
End of 2015	114	235	349	45	16	8	418
End of 2016	107	209	316	47	15	5	383
End of 2017	106	101	207	1	16	2	226
Equity affiliates							
End of 2014	-	-	-	-	-	53	53
End of 2015	-	-	-	-	-	50	50
End of 2016	-	-	-	-	-	47	47
End of 2017	-	-	-	-	-	45	45
Undeveloped							
Consolidated operations							
End of 2014	-	103	103	8	6	2	119
End of 2015	-	86	86	-	4	-	90
End of 2016	-	69	69	1	4	-	74
End of 2017	-	123	123	-	2	3	128
Equity affiliates							
End of 2014	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions in Lower 48 were primarily due to higher prices. In 2015, revisions in Lower 48 and Canada were primarily due to lower prices.

- *Extensions and discoveries*: 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 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.

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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 2014	2,719	6,945	9,664	1,916	1,573	1,878	227	15,258
Revisions	(293)	(884)	(1,177)	(111)	(27)	110	-	(1,205)
Improved recovery	-	-	-	1	-	8	-	9
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	4	103	107	44	-	2	-	153
Production	(83)	(588)	(671)	(261)	(187)	(285)	-	(1,404)
Sales	-	(405)	(405)	(482)	-	-	-	(887)
End of 2015	2,347	5,171	7,518	1,107	1,359	1,713	227	11,924
Revisions	(105)	(124)	(229)	111	56	18	-	(44)
Improved recovery	-	-	-	-	-	1	-	1
Purchases	-	-	-	1	-	-	-	1
Extensions and discoveries	2	162	164	43	-	124	-	331
Production	(73)	(494)	(567)	(192)	(177)	(288)	-	(1,224)
Sales	(69)	(1)	(70)	(33)	-	(42)	-	(145)
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
Equity affiliates								
End of 2014	-	-	-	-	-	5,242	-	5,242
Revisions	-	-	-	-	-	(2)	-	(2)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	268	-	268
Production	-	-	-	-	-	(239)	-	(239)
Sales	-	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	5,269	-	5,269
Revisions	-	-	-	-	-	(676)	-	(676)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	125	-	125
Production	-	-	-	-	-	(337)	-	(337)
Sales	-	-	-	-	-	-	-	-
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
Total company								
End of 2014	2,719	6,945	9,664	1,916	1,573	7,120	227	20,500
End of 2015	2,347	5,171	7,518	1,107	1,359	6,982	227	17,193
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

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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 2014	2,663	5,922	8,585	1,801	1,182	1,553	226	13,347
End of 2015	2,313	4,458	6,771	1,101	1,088	1,421	227	10,608
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
Equity affiliates								
End of 2014	-	-	-	-	-	3,954	-	3,954
End of 2015	-	-	-	-	-	4,482	-	4,482
End of 2016	-	-	-	-	-	4,110	-	4,110
End of 2017	-	-	-	-	-	4,044	-	4,044
Undeveloped								
Consolidated operations								
End of 2014	56	1,023	1,079	115	391	325	1	1,911
End of 2015	34	713	747	6	271	292	-	1,316
End of 2016	8	515	523	6	240	338	-	1,107
End of 2017	10	936	946	-	220	353	-	1,519
Equity affiliates								
End of 2014	-	-	-	-	-	1,288	-	1,288
End of 2015	-	-	-	-	-	787	-	787
End of 2016	-	-	-	-	-	271	-	271
End of 2017	-	-	-	-	-	259	-	259

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.

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, 2017, included:

- *Revisions*: In 2017, revisions in Alaska, Lower 48 and Europe were primarily due to higher prices. In 2016, revisions in our equity affiliates in Asia Pacific/Middle East were primarily due to lower prices. In 2015, revisions in Lower 48, Alaska and Canada were primarily due to lower prices, partially offset by positive revisions in Asia Pacific/Middle East from Indonesia.

- *Extensions and discoveries*: In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken. In 2015, for our equity affiliates in Asia Pacific/Middle East, extensions and discoveries were due to APLNG's ongoing development drilling onshore Australia.

- *Sales*: 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. In 2015, Lower 48 sales were due to the disposition of noncore assets in South Texas, East Texas and North Louisiana and sales of assets in British Columbia, Saskatchewan and Alberta impacted Canada.

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Years Ended December 31	Bitumen Millions of Barrels Canada
Developed and Undeveloped	
Consolidated operations	
End of 2014	598
Revisions	94
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(5)
Sales	-
End of 2015	687
Revisions	(515)
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(13)
Sales	-
End of 2016	159
Revisions	16
Improved recovery	-
Purchases	-
Extensions and discoveries	96
Production	(21)
Sales	-
End of 2017	250
Equity affiliates	
End of 2014	1,468
Revisions	190
Improved recovery	-
Purchases	-
Extensions and discoveries	99
Production	(51)
Sales	-
End of 2015	1,706
Revisions	(573)
Improved recovery	-
Purchases	-
Extensions and discoveries	10
Production	(54)
Sales	-
End of 2016	1,089
Revisions	-
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(23)
Sales	(1,066)
End of 2017	-
Total company	
End of 2014	2,066
End of 2015	2,393
End of 2016	1,248
End of 2017	250

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Years Ended December 31	Bitumen Millions of Barrels
	Canada
Developed	
Consolidated operations	
End of 2014	13
End of 2015	111
End of 2016	159
End of 2017	154
Equity affiliates	
End of 2014	187
End of 2015	311
End of 2016	322
End of 2017	-
Undeveloped	
Consolidated operations	
End of 2014	585
End of 2015	576
End of 2016	-
End of 2017	96
Equity affiliates	
End of 2014	1,281
End of 2015	1,395
End of 2016	767
End of 2017	-

Notable changes in proved bitumen reserves in the three years ended December 31, 2017, included:

- *Revisions*: In 2017, revisions were primarily due to higher prices at Surmont. In 2016, for both our consolidated operations and equity affiliates revisions were primarily related to lower prices which resulted in reserve reductions at Surmont, Foster Creek, Christina Lake and Narrows Lake. In 2015, for both our consolidated operations and equity affiliates revisions were primarily related to reduced royalties from lower prices at Surmont, Foster Creek, Christina Lake and Narrows Lake.

- *Extensions and discoveries*: 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. In 2015, for our equity affiliates extensions and discoveries were related to approval of development at Christina Lake.

- *Sales*: In 2017, sales were due to the disposition of our 50 percent interest in the FCCL Partnership.

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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	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
End of 2014	1,636	2,274	3,910	1,006	697	553	242	-	6,408
Revisions	(165)	(301)	(466)	66	(26)	(12)	-	-	(438)
Improved recovery	4	4	8	2	-	32	-	-	42
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	20	84	104	10	-	8	-	-	122
Production	(75)	(211)	(286)	(62)	(78)	(84)	-	-	(510)
Sales	-	(79)	(79)	(92)	-	-	-	-	(171)
End of 2015	1,420	1,771	3,191	930	593	497	242	-	5,453
Revisions	(77)	(143)	(220)	(484)	11	9	-	-	(684)
Improved recovery	6	3	9	-	-	7	-	-	16
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	33	124	157	9	-	28	-	-	194
Production	(76)	(185)	(261)	(55)	(76)	(87)	(1)	-	(480)
Sales	(12)	-	(12)	(7)	-	(10)	-	-	(29)
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
Equity affiliates									
End of 2014	-	-	-	1,468	-	1,025	-	5	2,498
Revisions	-	-	-	190	-	(1)	-	-	189
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	99	-	45	-	-	144
Production	-	-	-	(51)	-	(48)	-	(1)	(100)
Sales	-	-	-	-	-	-	-	(4)	(4)
End of 2015	-	-	-	1,706	-	1,021	-	-	2,727
Revisions	-	-	-	(573)	-	(113)	-	-	(686)
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	10	-	21	-	-	31
Production	-	-	-	(54)	-	(64)	-	-	(118)
Sales	-	-	-	-	-	-	-	-	-
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
Total company									
End of 2014	1,636	2,274	3,910	2,474	697	1,578	242	5	8,906
End of 2015	1,420	1,771	3,191	2,636	593	1,518	242	-	8,180
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

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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	Other Areas	Total
Developed									
Consolidated operations									
End of 2014	1,514	1,637	3,151	393	452	412	237	-	4,645
End of 2015	1,318	1,261	2,579	352	398	384	242	-	3,955
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
Equity affiliates									
End of 2014	-	-	-	187	-	810	-	5	1,002
End of 2015	-	-	-	311	-	890	-	-	1,201
End of 2016	-	-	-	322	-	820	-	-	1,142
End of 2017	-	-	-	-	-	802	-	-	802
Undeveloped									
Consolidated operations									
End of 2014	122	637	759	613	245	141	5	-	1,763
End of 2015	102	510	612	578	195	113	-	-	1,498
End of 2016	91	405	496	2	163	135	-	-	796
End of 2017	111	671	782	96	145	125	-	-	1,148
Equity affiliates									
End of 2014	-	-	-	1,281	-	215	-	-	1,496
End of 2015	-	-	-	1,395	-	131	-	-	1,526
End of 2016	-	-	-	767	-	45	-	-	812
End of 2017	-	-	-	-	-	43	-	-	43

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 1,191 million BOE of proved undeveloped reserves at year-end 2017, compared with 1,608 million BOE at year-end 2016. The following table shows changes in total proved undeveloped reserves for 2017:

	Proved Undeveloped Reserves Millions of Barrels of Oil Equivalent
End of 2016	1,608
Transfers to proved developed	(194)
Revisions	29
Improved recovery	6
Purchases	-
Extensions and discoveries	527
Sales	(785)
End of 2017	1,191

Sales were primarily due to the disposition of our 50 percent interest in the FCCL Partnership, which were partially offset by extensions and discoveries primarily in the Lower 48, Alaska, Canada and Asia Pacific/Middle East.

As a result, at December 31, 2017, our proved undeveloped reserves represented 24 percent of total proved reserves, compared with 25 percent at December 31, 2016. Costs incurred for the year ended December 31, 2017, relating to the development of proved undeveloped reserves were $3.5 billion. A portion of our costs incurred each year relates to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

At the end of 2017, more than 90 percent of total proved undeveloped reserves are currently 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 Europe and Asia Pacific/Middle East regions. All major development areas are currently producing and are expected to have proved undeveloped reserves convert to proved developed over time. Approximately 74 percent of our total proved undeveloped reserves at year-end 2017 are in North America, and all 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 2017, 2016 and 2015 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas 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.

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Results of Operations

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	985	1,669	2,654	609	775	574	44	-	4,656
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
	557	(4,765)	(4,208)	1,716	1,234	1,004	406	277	429
Income tax provision (benefit)	(678)	(2,424)	(3,102)	(651)	702	363	428	11	(2,249)
Results of operations	$ 1,235	(2,341)	(1,106)	2,367	532	641	(22)	266	2,678
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)

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Year Ended December 31, 2016	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars								
Consolidated operations									
Sales	$ 2,793	4,117	6,910	661	2,678	2,350	-	-	12,599
Transfers	8	-	8	-	-	347	-	-	355
Transportation costs	(676)	-	(676)	-	-	(40)	-	-	(716)
Other revenues	375	111	486	48	(34)	(25)	147	9	631
Total revenues	2,500	4,228	6,728	709	2,644	2,632	147	9	12,869
Production costs excluding taxes	1,056	1,967	3,023	790	795	640	23	(2)	5,269
Taxes other than income taxes	231	308	539	55	31	30	1	-	656
Exploration expenses	45	1,227	1,272	332	90	38	138	41	1,911
Depreciation, depletion and amortization	738	4,167	4,905	881	1,390	1,402	2	-	8,580
Impairments	1	148	149	88	(161)	44	-	-	120
Other related expenses	52	70	122	(51)	(77)	(13)	4	4	(11)
Accretion	52	72	124	32	210	35	-	-	401
	325	(3,731)	(3,406)	(1,418)	366	456	(21)	(34)	(4,057)
Income tax provision (benefit)	(29)	(1,349)	(1,378)	(406)	3	250	(72)	(13)	(1,616)
Results of operations	$ 354	(2,382)	(2,028)	(1,012)	363	206	51	(21)	(2,441)
Equity affiliates									
Sales	$ -	-	-	860	-	449	-	-	1,309
Transfers	-	-	-	-	-	825	-	-	825
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	(2)	-	-	(2)
Total revenues	-	-	-	860	-	1,272	-	-	2,132
Production costs excluding taxes	-	-	-	431	-	256	-	-	687
Taxes other than income taxes	-	-	-	15	-	476	-	-	491
Exploration expenses	-	-	-	6	-	-	-	-	6
Depreciation, depletion and amortization	-	-	-	309	-	548	-	-	857
Impairments	-	-	-	9	-	-	-	-	9
Other related expenses	-	-	-	(7)	-	8	-	24	25
Accretion	-	-	-	8	-	7	-	-	15
	-	-	-	89	-	(23)	-	(24)	42
Income tax provision (benefit)	-	-	-	24	-	(201)	-	-	(177)
Results of operations	$ -	-	-	65	-	178	-	(24)	219

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Year Ended December 31, 2015	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars								
Consolidated operations									
Sales	$ 3,206	4,992	8,198	930	3,637	2,741	-	-	15,506
Transfers	15	-	15	-	-	629	-	-	644
Transportation costs	(599)	-	(599)	-	-	(40)	-	-	(639)
Other revenues	(5)	452	447	(19)	(28)	6	13	2	421
Total revenues	2,617	5,444	8,061	911	3,609	3,336	13	2	15,932
Production costs excluding taxes	1,242	2,420	3,662	923	1,137	815	42	1	6,580
Taxes other than income taxes	281	358	639	62	35	33	3	1	773
Exploration expenses	682	1,583	2,265	457	170	268	990	43	4,193
Depreciation, depletion and amortization	548	4,192	4,740	777	1,813	1,321	-	-	8,651
Impairments	8	(2)	6	3	724	3	-	-	736
Other related expenses	(30)	78	48	8	9	(2)	(8)	5	60
Accretion	52	83	135	49	240	34	-	-	458
	(166)	(3,268)	(3,434)	(1,368)	(519)	864	(1,014)	(48)	(5,519)
Income tax provision (benefit)	(89)	(1,193)	(1,282)	(244)	(816)	430	(406)	(27)	(2,345)
Results of operations	$ (77)	(2,075)	(2,152)	(1,124)	297	434	(608)	(21)	(3,174)
Equity affiliates									
Sales	$ -	-	-	917	-	536	-	50	1,503
Transfers	-	-	-	-	-	950	-	-	950
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	34	-	4	-	58	96
Total revenues	-	-	-	951	-	1,490	-	108	2,549
Production costs excluding taxes	-	-	-	474	-	248	-	13	735
Taxes other than income taxes	-	-	-	15	-	723	-	13	751
Exploration expenses	-	-	-	12	-	190	-	-	202
Depreciation, depletion and amortization	-	-	-	367	-	197	-	5	569
Impairments	-	-	-	-	-	1,396	-	3	1,399
Other related expenses	-	-	-	(2)	-	(13)	-	23	8
Accretion	-	-	-	7	-	10	-	1	18
	-	-	-	78	-	(1,261)	-	50	(1,133)
Income tax provision (benefit)	-	-	-	20	-	(155)	-	10	(125)
Results of operations	$ -	-	-	58	-	(1,106)	-	40	(1,008)

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Statistics

Net Production	**2017**	2016	2015
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**167**	163	158
Lower 48	**180**	195	206
United States	**347**	358	364
Canada	**3**	7	12
Europe	**122**	120	120
Asia Pacific/Middle East	**93**	97	91
Africa	**20**	2	-
Total consolidated operations	**585**	584	587
Equity affiliates			
Asia Pacific/Middle East	**14**	14	14
Other areas	**-**	-	4
Total equity affiliates	**14**	14	18
Total company	**599**	**598**	**605**
Natural Gas Liquids			
Consolidated operations			
Alaska	**14**	12	13
Lower 48	**69**	88	94
United States	**83**	100	107
Canada	**9**	23	26
Europe	**8**	7	7
Asia Pacific/Middle East	**4**	7	9
Total consolidated operations	**104**	137	149
Equity affiliates—Asia Pacific/Middle East	**7**	8	7
Total company	**111**	**145**	**156**
Bitumen			
Consolidated operations—Canada	**59**	35	13
Equity affiliates—Canada	**63**	148	138
Total company	**122**	183	151
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**7**	25	42
Lower 48	**898**	1,219	1,472
United States	**905**	1,244	1,514
Canada	**187**	524	715
Europe	**476**	459	475
Asia Pacific/Middle East	**687**	730	717
Africa	**8**	1	1
Total consolidated operations	**2,263**	2,958	3,422
Equity affiliates—Asia Pacific/Middle East	**1,007**	899	638
Total company	**3,270**	**3,857**	**4,060**

Average Sales Prices	2017	2016	2015
Crude Oil Per Barrel			
Consolidated operations			
Alaska	**$ 42.69**	31.68	41.84
Lower 48	**47.36**	37.49	42.62
United States	**45.01**	34.70	42.27
Canada	**43.69**	35.25	39.52
Europe	**54.04**	43.66	52.75
Asia Pacific/Middle East	**54.38**	42.23	49.70
Africa	**55.11**	-	60.79
Total international	**54.16**	42.76	50.79
Total consolidated operations	**48.70**	37.67	45.48
Equity affiliates			
Asia Pacific/Middle East	**54.76**	44.11	53.12
Other areas	**-**	-	37.21
Total equity affiliates	**54.76**	44.11	49.92
Total operations	**48.84**	37.82	45.61
Natural Gas Liquids Per Barrel			
Consolidated operations			
Lower 48	**$ 22.20**	14.34	14.01
United States	**22.20**	14.34	14.01
Canada	**21.51**	14.82	17.02
Europe	**34.07**	22.62	27.56
Asia Pacific/Middle East	**41.37**	29.00	37.78
Total international	**30.34**	19.06	23.21
Total consolidated operations	**24.21**	15.72	16.83
Equity affiliates—Asia Pacific/Middle East	**38.74**	31.13	35.79
Total operations	**25.22**	16.68	17.79
Bitumen Per Barrel			
Consolidated operations—Canada	**$ 21.43**	12.91	20.13
Equity affiliates—Canada	**23.83**	15.80	18.58
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 2.72**	5.22	4.33
Lower 48	**2.73**	2.20	2.43
United States	**2.73**	2.24	2.47
Canada	**1.93**	1.49	1.91
Europe	**5.72**	4.71	7.14
Asia Pacific/Middle East	**4.66**	4.15	6.08
Africa	**3.53**	-	-
Total international	**4.64**	3.49	4.78
Total consolidated operations	**3.87**	2.97	3.77
Equity affiliates—Asia Pacific/Middle East	**4.27**	2.97	4.83
Total operations	**4.00**	2.97	3.93

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.

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	2017	2016	2015
Average Production Costs Per Barrel of Oil Equivalent*			
Consolidated operations			
Alaska	**$ 14.83**	16.12	19.12
Lower 48	**11.46**	11.06	12.17
United States	**12.52**	12.42	13.88
Canada	**16.36**	14.20	14.88
Europe	**10.16**	10.70	15.05
Asia Pacific/Middle East	**7.42**	7.74	10.20
Africa	**5.74**	31.42	-
Total international	**10.08**	10.53	13.41
Total consolidated operations	**11.34**	11.54	13.67
Equity affiliates			
Canada	**7.57**	7.96	9.41
Asia Pacific/Middle East	**5.26**	4.04	5.31
Other areas	**-**	-	8.90
Total equity affiliates	**5.84**	5.85	7.46
Average Production Costs Per Barrel—Bitumen			
Consolidated operations—Canada	**$ 14.63**	24.59	61.87
Equity affiliates—Canada	**18.74**	7.96	9.41
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 4.14**	3.53	4.33
Lower 48	**2.18**	1.73	1.80
United States	**2.80**	2.21	2.42
Canada	**0.89**	0.99	1.00
Europe	**0.42**	0.42	0.46
Asia Pacific/Middle East	**0.50**	0.36	0.41
Africa	**0.26**	1.37	-
Total international	**0.53**	0.55	0.62
Total consolidated operations	**1.70**	1.44	1.61
Equity affiliates			
Canada	**0.30**	0.28	0.30
Asia Pacific/Middle East	**8.76**	7.52	15.48
Other areas	**-**	-	8.90
Total equity affiliates	**6.64**	4.18	7.62
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 10.99**	11.26	8.43
Lower 48	**18.44**	23.43	21.07
United States	**16.10**	20.15	17.96
Canada	**11.76**	15.84	12.52
Europe	**16.18**	18.71	24.00
Asia Pacific/Middle East	**16.58**	16.95	16.53
Africa	**2.09**	2.73	-
Total international	**14.96**	17.22	17.98
Total consolidated operations	**15.55**	18.78	17.97
Equity affiliates			
Canada	**6.52**	5.70	7.29
Asia Pacific/Middle East	**8.94**	8.65	4.22
Other areas	**-**	-	3.42

Total equity affiliates	**8.34**	7.29	5.77

**Includes bitumen.*

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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, 2017, 2016 and 2015. 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 coalbed methane test wells located in Asia Pacific/Middle East.

Net Wells Completed	Productive			Dry		
	2017	2016	2015	**2017**	2016	2015
Exploratory						
Consolidated operations						
Alaska	**-**	2	-	**-**	1	-
Lower 48	**13**	8	47	**3**	1	4
United States	**13**	10	47	**3**	2	4
Canada	**13**	8	16	**-**	1	3
Europe	*	*	*	*	1	*
Asia Pacific/Middle East	**1**	1	1	**1**	-	2
Africa	**-**	1	*	**-**	-	*
Other areas	**-**	-	-	**1**	-	-
Total consolidated operations	**27**	20	64	**5**	4	9
Equity affiliates						
Asia Pacific/Middle East	**14**	20	19	**-**	-	*
Total equity affiliates	**14**	20	19	**-**	-	-
Development						
Consolidated operations						
Alaska	**9**	9	18	**-**	-	-
Lower 48	**161**	119	347	**-**	-	-
United States	**170**	128	365	**-**	-	-
Canada	**13**	47	47	**-**	2	-
Europe	**7**	7	10	**-**	-	-
Asia Pacific/Middle East	**8**	6	3	**-**	-	*
Africa	**-**	-	-	**-**	-	-
Other areas	**-**	-	-	**-**	-	-
Total consolidated operations	**198**	188	425	**-**	2	-
Equity affiliates						
Canada	**19**	48	22	**-**	-	-
Asia Pacific/Middle East	**84**	108	166	**-**	-	2
Other areas	**-**	-	*	**-**	-	-
Total equity affiliates	**103**	156	188	**-**	-	2

**Our total proportionate interest was less than one.*

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The table below represents the status of our wells drilling at December 31, 2017, 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, 2017.

Wells at December 31, 2017			Productive*			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	1	1	1,721	769	-	-
Lower 48	354	179	9,984	4,781	5,222	2,364
United States	355	180	11,705	5,550	5,222	2,364
Canada	1	1	182	91	42	34
Europe	22	3	486	86	181	68
Asia Pacific/Middle East	3	1	370	153	55	28
Africa	-	-	825	135	9	2
Total consolidated operations	381	185	13,568	6,015	5,509	2,496
Equity affiliates						
Asia Pacific/Middle East	176	47	-	-	3,749	907
Total equity affiliates	176	47	-	-	3,749	907

**Includes 18 gross and 6 net multiple completion wells.*

Acreage at December 31, 2017	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	592	294	1,345	1,014
Lower 48	2,278	1,934	10,632	8,509
United States	2,870	2,228	11,977	9,523
Canada	187	105	3,251	1,772
Europe	797	244	2,454	720
Asia Pacific/Middle East	1,596	742	12,568	6,462
Africa	358	59	12,545	2,049
Other areas	-	-	560	323
Total consolidated operations	5,808	3,378	43,355	20,849
Equity affiliates				
Asia Pacific/Middle East	872	201	5,445	1,432
Total equity affiliates	872	201	5,445	1,432

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Costs Incurred

Year Ended December 31	Millions of Dollars Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East *	Africa	Other Areas	Total
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
2016									
Consolidated operations									
Unproved property acquisition	$ -	127	127	59	-	-	-	-	186
Proved property acquisition	-	5	5	19	-	-	-	-	24
	-	132	132	78	-	-	-	-	210
Exploration	110	656	766	286	65	52	215	67	1,451
Development	720	782	1,502	209	62	387	6	-	2,166
	$ 830	1,570	2,400	573	127	439	221	67	3,827
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	2	-	-	2
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	2	-	-	2

Exploration	-	-	-	15	-	19	-	-	34
Development	-	-	-	367	-	320	-	-	687
	$ -	-	-	382	-	341	-	-	723
2015									
Consolidated operations									
Unproved property acquisition	$ -	168	168	52	-	-	-	-	220
Proved property acquisition	-	5	5	1	-	-	-	-	6
	-	173	173	53	-	-	-	-	226
Exploration	87	1,369	1,456	298	107	118	394	47	2,420
Development	1,217	2,875	4,092	827	1,742	587	4	-	7,252
	$ 1,304	4,417	5,721	1,178	1,849	705	398	47	9,898
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	-	-	-	-
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Exploration	-	-	-	17	-	60	-	-	77
Development	-	-	-	847	-	753	-	3	1,603
	$ -	-	-	864	-	813	-	3	1,680

**Certain amounts in Asia Pacific/Middle East equity affiliates have been revised in 2016 and 2015 to reflect additional abandonment obligations.*

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Capitalized Costs

At December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East *	Africa	Other Areas	Total
2017									
Consolidated operations									
Proved property	$ 18,149	35,332	53,481	6,217	27,221	14,236	889	-	102,044
Unproved property	1,068	1,137	2,205	985	290	822	122	67	4,491
	19,217	36,469	55,686	7,202	27,511	15,058	1,011	67	106,535
Accumulated depreciation, depletion and amortization	9,497	24,211	33,708	1,582	18,068	8,916	312	9	62,595
	$ 9,720	12,258	21,978	5,620	9,443	6,142	699	58	43,940
Equity affiliates									
Proved property	$ -	-	-	-	-	9,750	-	-	9,750
Unproved property	-	-	-	-	-	2,215	-	-	2,215
	-	-	-	-	-	11,965	-	-	11,965
Accumulated depreciation, depletion and amortization	-	-	-	-	-	5,342	-	-	5,342
	$ -	-	-	-	-	6,623	-	-	6,623
2016									
Consolidated operations									
Proved property	$ 17,376	46,050	63,426	16,970	24,858	13,837	879	-	119,970
Unproved property	1,099	1,376	2,475	1,435	269	787	123	61	5,150
	18,475	47,426	65,901	18,405	25,127	14,624	1,002	61	125,120
Accumulated depreciation, depletion and amortization	8,548	26,858	35,406	10,344	15,754	7,635	297	1	69,437
	$ 9,927	20,568	30,495	8,061	9,373	6,989	705	60	55,683
Equity affiliates									
Proved property	$ -	-	-	9,459	-	8,839	-	-	18,298
Unproved property	-	-	-	891	-	2,756	-	-	3,647
	-	-	-	10,350	-	11,595	-	-	21,945
Accumulated depreciation, depletion and amortization	-	-	-	1,906	-	1,369	-	-	3,275
	$ -	-	-	8,444	-	10,226	-	-	18,670

**Certain amounts in Asia Pacific/Middle East equity affiliates have been revised in 2016 to reflect additional abandonment obligations.*

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

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
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

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	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2016								
Consolidated operations								
Future cash inflows	$ 29,697	31,963	61,660	4,739	18,533	12,770	10,715	108,417
Less:								
Future production costs	24,965	16,936	41,901	5,103	7,469	5,288	1,420	61,181
Future development costs	7,961	8,932	16,893	1,586	9,949	2,777	537	31,742
Future income tax provisions (benefit)	—	744	744	—	(325)	1,563	7,885	9,867
Future net cash flows	(3,229)	5,351	2,122	(1,950)	1,440	3,142	873	5,627
10 percent annual discount	(3,143)	976	(2,167)	(1,297)	(2)	572	370	(2,524)
Discounted future net cash flows	$ (86)	4,375	4,289	(653)	1,442	2,570	503	8,151
Equity affiliates								
Future cash inflows	$ —	—	—	15,139	—	17,829	—	32,968
Less:								
Future production costs	—	—	—	8,514	—	10,620	—	19,134
Future development costs	—	—	—	4,993	—	980	—	5,973
Future income tax provisions	—	—	—	164	—	1,309	—	1,473
Future net cash flows	—	—	—	1,468	—	4,920	—	6,388
10 percent annual discount	—	—	—	540	—	1,911	—	2,451
Discounted future net cash flows	$ —	—	—	928	—	3,009	—	3,937
Total company								
Discounted future net cash flows	$ (86)	4,375	4,289	275	1,442	5,579	503	12,088

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	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2015								
Consolidated operations								
Future cash inflows	$ 44,054	42,575	86,629	22,317	27,782	19,368	13,875	169,971
Less:								
Future production costs	32,732	21,638	54,370	13,103	10,574	7,529	1,422	86,998
Future development costs	9,885	12,967	22,852	6,471	12,793	2,884	437	45,437
Future income tax provisions	-	844	844	-	1,506	2,708	10,998	16,056
Future net cash flows	1,437	7,126	8,563	2,743	2,909	6,247	1,018	21,480
10 percent annual discount	(502)	1,573	1,071	1,265	733	1,349	500	4,918
Discounted future net cash flows	$ 1,939	5,553	7,492	1,478	2,176	4,898	518	16,562
Equity affiliates								
Future cash inflows	$ -	-	-	36,211	-	34,257	-	70,468
Less:								
Future production costs	-	-	-	16,417	-	17,874	-	34,291
Future development costs	-	-	-	11,869	-	2,391	-	14,260
Future income tax provisions	-	-	-	1,648	-	3,117	-	4,765
Future net cash flows	-	-	-	6,277	-	10,875	-	17,152
10 percent annual discount	-	-	-	3,827	-	4,298	-	8,125
Discounted future net cash flows	$ -	-	-	2,450	-	6,577	-	9,027
Total company								
Discounted future net cash flows	$ 1,939	5,553	7,492	3,928	2,176	11,475	518	25,589

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Discounted future net cash flows at the beginning of the year	**$ 8,151**	16,562	56,348	**3,937**	9,027	26,869	**12,088**	25,589	83,217
Changes during the year									
Revenues less production costs for the year	**(9,844)**	(6,313)	(8,158)	**(1,341)**	(956)	(966)	**(11,185)**	(7,269)	(9,124)
Net change in prices and production costs	**19,310**	(16,476)	(82,923)	**2,750**	(9,317)	(27,670)	**22,060**	(25,793)	(110,593)
Extensions, discoveries and improved recovery, less estimated future costs	**1,445**	1,358	1,791	**(4)**	(77)	319	**1,441**	1,281	2,110
Development costs for the year	**3,653**	3,118	6,854	**426**	722	1,493	**4,079**	3,840	8,347
Changes in estimated future development costs	**1,225**	6,646	2,073	**(64)**	2,435	(227)	**1,161**	9,081	1,846
Purchases of reserves in place, less estimated future costs	**-**	2	-	**-**	-	-	**-**	2	-
Sales of reserves in place, less estimated future costs	**(855)**	(123)	(424)	**(786)**	-	(38)	**(1,641)**	(123)	(462)
Revisions of previous quantity estimates	**2,300**	(3,252)	(1,790)	**(648)**	(436)	938	**1,652**	(3,688)	(852)
Accretion of discount	**1,313**	2,540	9,342	**413**	1,058	3,297	**1,726**	3,598	12,639
Net change in income taxes	**(6,089)**	4,089	33,449	**(288)**	1,481	5,012	**(6,377)**	5,570	38,461
Total changes	**12,458**	(8,411)	(39,786)	**458**	(5,090)	(17,842)	**12,916**	(13,501)	(57,628)
Discounted future net cash flows at year end	**$ 20,609**	8,151	16,562	**4,395**	3,937	9,027	**25,004**	12,088	25,589

- 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
2017						
First	**$ 7,518**	**(232)**	**599**	**586**	**0.47**	**0.47**
Second	**6,781**	**(4,361)**	**(3,426)**	**(3,440)**	**(2.78)**	**(2.78)**
Third	**6,688**	**653**	**436**	**420**	**0.35**	**0.34**
Fourth	**8,119**	**1,325**	**1,598**	**1,579**	**1.32**	**1.32**
2016						
First	$ 5,121	(2,224)	(1,456)	(1,469)	(1.18)	(1.18)
Second	5,348	(1,644)	(1,058)	(1,071)	(0.86)	(0.86)
Third	6,415	(1,654)	(1,026)	(1,040)	(0.84)	(0.84)
Fourth	6,809	(8)	(19)	(35)	(0.03)	(0.03)

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 ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Canada Funding Company I is an indirect, 100 percent owned subsidiary of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Canada Funding Company I, with respect to their 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 ConocoPhillips Canada Funding Company I (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 2015, ConocoPhillips received a $3.5 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips received a $2.3 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips Canada Funding Company I repaid $1.25 billion of external debt. This transaction was reflected in the full-year 2016 condensed consolidating financial statements.

In 2017, ConocoPhillips Company received a $9.8 billion return of capital from a nonguarantor subsidiary to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2017, ConocoPhillips received a $5.0 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2017, ConocoPhillips received a $3.0 billion distribution from ConocoPhillips Company to settle certain accumulated intercompany balances. This consisted of a $2.8 billion return of capital and a $0.2 billion return of earnings. This transaction had no impact on our consolidated financial statements.

In 2017, ConocoPhillips Company received a $1.4 billion loan repayment from a nonguarantor subsidiary to settle certain accumulated intercompany balances. This transaction 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.

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Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	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	-	630	(1,451)	772
Gain on dispositions	-	916	-	1,261	-	2,177
Other income	2	35	-	492	-	529
Intercompany revenues	48	291	170	3,405	(3,914)	-
Total Revenues and Other Income	(404)	15,722	170	22,461	(5,365)	32,584
Costs and Expenses						
Purchased commodities	-	11,145	-	4,580	(3,250)	12,475
Production and operating expenses	-	832	-	4,358	(17)	5,173
Selling, general and administrative expenses	9	476	-	82	(6)	561
Exploration expenses	-	544	-	394	-	938
Depreciation, depletion and amortization	-	855	-	5,990	-	6,845
Impairments	-	1,159	-	5,442	-	6,601
Taxes other than income taxes	-	140	-	669	-	809
Accretion on discounted liabilities	-	32	-	330	-	362
Interest and debt expense	420	664	147	508	(641)	1,098
Foreign currency transaction (gains) losses	(43)	11	156	(89)	-	35
Other expense	267	35	-	-	-	302
Total Costs and Expenses	653	15,893	303	22,264	(3,914)	35,199
Income (Loss) before income taxes	(1,057)	(171)	(133)	197	(1,451)	(2,615)
Income tax provision (benefit)	(202)	283	7	(1,910)	-	(1,822)
Net income (loss)	(855)	(454)	(140)	2,107	(1,451)	(793)
Less: net income attributable to noncontrolling interests	-	-	-	(62)	-	(62)
Net Income (Loss) Attributable to ConocoPhillips	$ (855)	(454)	(140)	2,045	(1,451)	(855)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ (180)	221	23	2,703	(2,947)	(180)
Income Statement	Year Ended December 31, 2016					
Revenues and Other Income						
Sales and other operating revenues	$ -	10,352	-	13,341	-	23,693
Equity in earnings (losses) of affiliates	(3,351)	(1,051)	-	(91)	4,545	52
Gain on dispositions	-	120	-	240	-	360
Other income	1	(11)	-	265	-	255
Intercompany revenues	88	277	220	3,036	(3,621)	-
Total Revenues and Other Income	(3,262)	9,687	220	16,791	924	24,360
Costs and Expenses						
Purchased commodities	-	9,144	-	3,562	(2,712)	9,994
Production and operating expenses	-	779	-	5,131	(243)	5,667
Selling, general and administrative expenses	8	581	-	140	(6)	723
Exploration expenses	-	1,231	-	684	-	1,915
Depreciation, depletion and amortization	-	1,178	-	7,884	-	9,062
Impairments	-	67	-	72	-	139
Taxes other than income taxes	-	162	-	577	-	739
Accretion on discounted liabilities	-	46	-	379	-	425
Interest and debt expense	506	622	207	570	(660)	1,245
Foreign currency transaction (gains) losses	(19)	2	174	(176)	-	(19)
Total Costs and Expenses	495	13,812	381	18,823	(3,621)	29,890
Loss before income taxes	(3,757)	(4,125)	(161)	(2,032)	4,545	(5,530)
Income tax benefit	(142)	(774)	(9)	(1,046)	-	(1,971)
Net loss	(3,615)	(3,351)	(152)	(986)	4,545	(3,559)
Less: net income attributable to noncontrolling interests	-	-	-	(56)	-	(56)
Net Loss Attributable to ConocoPhillips	$ (3,615)	(3,351)	(152)	(1,042)	4,545	(3,615)
Comprehensive Loss Attributable to ConocoPhillips	$ (3,561)	(3,297)	(27)	(952)	4,276	(3,561)

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Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2015					
Revenues and Other Income						
Sales and other operating revenues	$ -	11,473	-	18,091	-	29,564
Equity in earnings (losses) of affiliates	(4,081)	(1,950)	-	1,364	5,322	655
Gain on dispositions	-	332	-	259	-	591
Other income	-	12	-	113	-	125
Intercompany revenues	74	341	246	3,365	(4,026)	-
Total Revenues and Other Income	(4,007)	10,208	246	23,192	1,296	30,935
Costs and Expenses						
Purchased commodities	-	9,905	-	5,838	(3,317)	12,426
Production and operating expenses	-	1,469	-	5,585	(38)	7,016
Selling, general and administrative expenses	9	744	1	209	(10)	953
Exploration expenses	-	2,093	-	2,099	-	4,192
Depreciation, depletion and amortization	-	1,201	-	7,912	-	9,113
Impairments	-	15	-	2,230	-	2,245
Taxes other than income taxes	-	173	-	728	-	901
Accretion on discounted liabilities	-	58	-	425	-	483
Interest and debt expense	485	423	226	447	(661)	920
Foreign currency transaction (gains) losses	114	1	(708)	518	-	(75)
Total Costs and Expenses	608	16,082	(481)	25,991	(4,026)	38,174
Income (loss) before income taxes	(4,615)	(5,874)	727	(2,799)	5,322	(7,239)
Income tax provision (benefit)	(187)	(1,793)	21	(909)	-	(2,868)
Net income (loss)	(4,428)	(4,081)	706	(1,890)	5,322	(4,371)
Less: net income attributable to noncontrolling interests	-	-	-	(57)	-	(57)
Net Income (Loss) Attributable to ConocoPhillips	$ (4,428)	(4,081)	706	(1,947)	5,322	(4,428)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ (8,773)	(8,426)	71	(6,705)	15,060	(8,773)

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Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	At December 31, 2017					
Assets						
Cash and cash equivalents	$ -	234	4	6,087	-	6,325
Short-term investments	-	-	-	1,873	-	1,873
Accounts and notes receivable	24	2,255	35	4,870	(2,864)	4,320
Investment in Cenovus Energy	-	1,899	-	-	-	1,899
Inventories	-	163	-	897	-	1,060
Prepaid expenses and other current assets	1	278	6	779	(29)	1,035
Total Current Assets	25	4,829	45	14,506	(2,893)	16,512
Investments, loans and long-term receivables*	29,400	47,974	2,533	15,050	(84,897)	10,060
Net properties, plants and equipment	-	4,230	-	41,930	(477)	45,683
Other assets	15	1,146	186	1,302	(1,542)	1,107
Total Assets	$ 29,440	58,179	2,764	72,788	(89,809)	73,362
Liabilities and Stockholders' Equity						
Accounts payable	$ -	3,094	1	3,799	(2,864)	4,030
Short-term debt	(5)	2,505	7	77	(9)	2,575
Accrued income and other taxes	-	107	-	931	-	1,038
Employee benefit obligations	-	554	-	171	-	725
Other accruals	85	314	48	612	(30)	1,029
Total Current Liabilities	80	6,574	56	5,590	(2,903)	9,397
Long-term debt	3,787	9,321	1,703	2,794	(477)	17,128
Asset retirement obligations and accrued environmental costs	-	432	-	7,199	-	7,631
Deferred income taxes	-	-	-	6,263	(981)	5,282
Employee benefit obligations	-	1,335	-	519	-	1,854
Other liabilities and deferred credits*	1,528	5,229	926	9,215	(15,629)	1,269
Total Liabilities	5,395	22,891	2,685	31,580	(19,990)	42,561
Retained earnings	22,867	13,317	(681)	11,958	(18,070)	29,391
Other common stockholders' equity	1,178	21,971	760	29,056	(51,749)	1,216
Noncontrolling interests	-	-	-	194	-	194
Total Liabilities and Stockholders' Equity	$ 29,440	58,179	2,764	72,788	(89,809)	73,362

Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	At December 31, 2016					
Assets						
Cash and cash equivalents	$ -	358	13	3,239	-	3,610
Short-term investments	-	-	-	50	-	50
Accounts and notes receivable	22	1,968	23	6,103	(4,702)	3,414
Inventories	-	84	-	934	-	1,018
Prepaid expenses and other current assets	2	116	8	415	(24)	517
Total Current Assets	24	2,526	44	10,741	(4,726)	8,609
Investments, loans and long-term receivables*	37,901	64,434	2,296	31,643	(114,602)	21,672
Net properties, plants and equipment	-	6,301	-	52,030	-	58,331
Other assets	40	2,194	220	1,240	(2,534)	1,160
Total Assets	$ 37,965	75,455	2,560	95,654	(121,862)	89,772
Liabilities and Stockholders' Equity						
Accounts payable	$ -	4,683	1	3,671	(4,702)	3,653
Short-term debt	(10)	999	6	94	-	1,089
Accrued income and other taxes	-	85	-	399	-	484
Employee benefit obligations	-	489	-	200	-	689
Other accruals	171	271	40	536	(24)	994
Total Current Liabilities	161	6,527	47	4,900	(4,726)	6,909
Long-term debt	8,975	12,635	1,710	2,866	-	26,186
Asset retirement obligations and accrued environmental costs	-	925	-	7,500	-	8,425
Deferred income taxes	-	-	-	10,972	(2,023)	8,949
Employee benefit obligations	-	1,901	-	651	-	2,552
Other liabilities and deferred credits*	417	10,391	748	17,832	(27,863)	1,525
Total Liabilities	9,553	32,379	2,505	44,721	(34,612)	54,546
Retained earnings	25,025	14,015	(541)	12,883	(19,834)	31,548
Other common stockholders' equity	3,387	29,061	596	37,798	(67,416)	3,426
Noncontrolling interests	-	-	-	252	-	252
Total Liabilities and Stockholders' Equity	$ 37,965	75,455	2,560	95,654	(121,862)	89,772

Includes intercompany loans.

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Statement of Cash Flows	Millions of Dollars					
	Year Ended December 31, 2017					
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ 71	1,183	(74)	8,931	(3,034)	7,077
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(1,663)	-	(3,795)	867	(4,591)
Working capital changes associated with investing activities	-	194	-	(62)	-	132
Proceeds from asset dispositions	7,765	11,146	-	12,796	(17,847)	13,860
Net purchases of short-term investments	-	-	-	(1,790)	-	(1,790)
Long-term advances/loans—related parties	-	(214)	-	(85)	299	-
Collection of advances/loans—related parties	658	1,527	-	2,196	(4,266)	115
Intercompany cash management	1,151	101	-	(1,252)	-	-
Other	-	(8)	-	44	-	36
Net Cash Provided by Investing Activities	9,574	11,083	-	8,052	(20,947)	7,762
Cash Flows From Financing Activities						
Issuance of debt	-	20	65	214	(299)	-
Repayment of debt	(5,459)	(4,411)	-	(2,272)	4,266	(7,876)
Issuance of company common stock	115	-	-	-	(178)	(63)
Repurchase of company common stock	(3,000)	-	-	-	-	(3,000)
Dividends paid	(1,305)	(235)	-	(2,977)	3,212	(1,305)
Other	4	(7,765)	-	(9,331)	16,980	(112)
Net Cash Provided by (Used in) Financing Activities	(9,645)	(12,391)	65	(14,366)	23,981	(12,356)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	1	-	231	-	232
Net Change in Cash and Cash Equivalents	-	(124)	(9)	2,848	-	2,715
Cash and cash equivalents at beginning of period	-	358	13	3,239	-	3,610
Cash and Cash Equivalents at End of Period	$ -	234	4	6,087	-	6,325

Statement of Cash Flows	Year Ended December 31, 2016					
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ (306)	(322)	(2)	5,903	(870)	4,403
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(989)	-	(4,281)	401	(4,869)
Working capital changes associated with investing activities	-	(126)	-	(205)	-	(331)
Proceeds from asset dispositions	2,300	266	-	1,114	(2,394)	1,286
Net purchases of short-term investments	-	-	-	(51)	-	(51)
Long-term advances/loans—related parties	-	(812)	-	-	812	-
Collection of advances/loans—related parties	-	391	1,250	272	(1,805)	108
Intercompany cash management	(2,214)	1,433	-	781	-	-
Other	-	1	-	(3)	-	(2)
Net Cash Provided by (Used in) Investing Activities	86	164	1,250	(2,373)	(2,986)	(3,859)
Cash Flows From Financing Activities						
Issuance of debt	1,600	2,994	-	812	(812)	4,594
Repayment of debt	(150)	(164)	(1,250)	(2,492)	1,805	(2,251)
Issuance of company common stock	148	-	-	-	(211)	(63)
Repurchase of company common stock	(126)	-	-	-	-	(126)
Dividends paid	(1,253)	-	-	(1,081)	1,081	(1,253)
Other	1	(2,315)	-	184	1,993	(137)
Net Cash Provided by (Used in) Financing Activities	220	515	(1,250)	(2,577)	3,856	764
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	(3)	-	(63)	-	(66)
Net Change in Cash and Cash Equivalents	-	354	(2)	890	-	1,242
Cash and cash equivalents at beginning of period	-	4	15	2,349	-	2,368
Cash and Cash Equivalents at End of Period	$ -	358	13	3,239	-	3,610

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Statement of Cash Flows	Millions of Dollars Year Ended December 31, 2015					
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ (225)	245	9	7,519	24	7,572
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(3,064)	-	(8,386)	1,400	(10,050)
Working capital changes associated with investing activities	-	(4)	-	(964)	-	(968)
Proceeds from asset dispositions	3,500	826	-	1,225	(3,599)	1,952
Long-term advances/loans—related parties	-	(278)	-	(2,245)	2,523	-
Collection of advances/loans—related parties	-	-	-	205	(100)	105
Intercompany cash management	102	46	-	(148)	-	-
Other	-	304	-	1	1	306
Net Cash Provided by (Used in) Investing Activities	3,602	(2,170)	-	(10,312)	225	(8,655)
Cash Flows From Financing Activities						
Issuance of debt	-	4,743	-	278	(2,523)	2,498
Repayment of debt	-	(100)	-	(103)	100	(103)
Issuance of company common stock	283	-	-	(2)	(363)	(82)
Dividends paid	(3,664)	-	-	(339)	339	(3,664)
Other	4	(3,484)	-	1,204	2,198	(78)
Net Cash Provided by (Used in) Financing Activities	(3,377)	1,159	-	1,038	(249)	(1,429)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	-	(1)	(181)	-	(182)
Net Change in Cash and Cash Equivalents	-	(766)	8	(1,936)	-	(2,694)
Cash and cash equivalents at beginning of period	-	770	7	4,285	-	5,062
Cash and Cash Equivalents at End of Period	$ -	4	15	2,349	-	2,368

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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, 2017, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, Commercial 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, Finance, Commercial and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 2017.

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 78 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on page 26.

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 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, 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 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, 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 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, 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 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, 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 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2018, 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 2018 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.*

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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 177 through 187, are filed as part of this annual report.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

	Millions of Dollars					
Description	Balance at January 1	Charged to Expense		Other(a)	Deductions		Balance at December 31
2017							
Deducted from asset accounts:							
Allowance for doubtful accounts and notes receivable	**$ 5**	**2**		**-**	**(3** | **) (b)**	**4**
Deferred tax asset valuation allowance	**675**	**560**	**(c)**	**19**	**-**		**1,254**
Included in other liabilities:							
Restructuring accruals	**80**	**65**		**1**	**(93** | **) (d)**	**53**
2016							
Deducted from asset accounts:							
Allowance for doubtful accounts and notes receivable	$ 7	3		(1)	(4	) (b)	5
Deferred tax asset valuation allowance	734	(31)		(12)	(16	)	675
Included in other liabilities:							
Restructuring accruals	156	129		1	(206	) (d)	80
2015							
Deducted from asset accounts:							
Allowance for doubtful accounts and notes receivable	$ 5	4		(2)	-	(b)	7
Deferred tax asset valuation allowance	970	6		(21)	(221	)	734
Included in other liabilities:							
Restructuring accruals	61	303		(8)	(200	) (d)	156

(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)Includes an adjustment to the U.S. tax basis due to U.S. Tax Legislation.
(d)Benefit payments.

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.
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	Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.10.2	First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated July 20, 2015 (incorporated by reference to Exhibit 10.10.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.10.3	Second Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated March 14, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.11.1	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.2	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.3	First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).

Exhibit Number	Description
10.11.4	Second Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated December 17, 2015 (incorporated by reference to Exhibit 10.11.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
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).
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	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.17.1	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).
10.17.2	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).
10.17.3	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).
10.17.4	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).
10.17.5	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).
10.17.6	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).

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Exhibit Number	Description
10.17.7	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).
10.17.8	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).
10.18.1	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).
10.18.2	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).
10.19	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).
10.20.1	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated April 19, 2012 (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).
10.20.2	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated April 19, 2012 (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).
10.20.3	First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.4	Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.5	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, 2013 Restatement dated November 17, 2014 (Amended and Restated effective as of January 1, 2013) (incorporated by reference to Exhibit 10.20.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2014; File No. 001-32395).
10.21	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).

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Exhibit Number	Description
10.22	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).
10.23.1	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).
10.23.2	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).
10.23.3	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).
10.24	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).
10.25	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).
10.26.1	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).
10.26.2	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).
10.26.3	Form of Restricted Stock Units Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective April 4, 2012 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.26.4	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective May 8, 2012 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.26.5	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).

Exhibit Number	Description
10.26.6	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).
10.26.7	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).
10.26.8	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).
10.26.9	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).
10.26.10	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).
10.26.11	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).
10.26.12	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).
10.26.13	Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.14	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).
10.26.15	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).

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Exhibit Number	Description
10.26.16	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).
10.26.17	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).
10.26.18	Form of Performance Period X 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 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.19	Form of Performance Period XII 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 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.20	Form of Performance Period XII 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 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.21	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).
10.26.22	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).
10.26.23	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).
10.26.24*	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.

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Exhibit Number	Description
10.26.25*	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.
10.27.1	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).
10.27.2	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program of ConocoPhillips, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 15, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2014; File No. 001-32395).
10.27.3	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).
10.27.4	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).
10.27.5	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).
10.27.6	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 Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.27.7	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).
10.27.8	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).

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Exhibit Number	Description
10.27.9	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).
10.27.10	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).
10.27.11	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).
10.27.12*	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.
10.27.13*	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.
10.27.14*	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.
10.27.15*	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.
10.28	Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (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).
10.29	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).
10.30	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).

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Exhibit Number	Description
10.31	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).
10.32	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).
10.33	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).
10.34	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).
10.35	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 26, 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).
10.36	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).
10.37	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).
10.38	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).
12*	Computation of Ratio of Earnings to Fixed Charges.
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.

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Exhibit Number	Description
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* *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.*

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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 20, 2018	*/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 20, 2018, 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, Finance, Commercial and Chief Financial Officer (Principal financial officer)
/s/ Glenda M. Schwarz Glenda M. Schwarz	Vice President and Controller (Principal accounting officer)

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/s/ Richard L. Armitage Richard L. Armitage	Director
/s/ Richard H. Auchinleck Richard H. Auchinleck	Director
/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/ Sharmila Mulligan Sharmila Mulligan	Director
/s/ Arjun N. Murti Arjun N. Murti	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ Harald J. Norvik Harald J. Norvik	Director