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 EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 2021**

OR

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

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

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

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

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

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

Title of each class	Trading symbols	Name of each exchange on which registered
Common Stock, $.01 Par Value	COP	New York Stock Exchange
7% Debentures due 2029	CUSIP—718507BK1	New York Stock Exchange

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

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

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

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

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

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

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

Indicate by check mark whether the registrant 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, 2021, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $60.90, was $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)

Table of Contents

Commonly Used Abbreviations

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

Currencies

$ or USD	U.S. dollar
CAD	Canadian dollar
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 obligation
ASC	accounting standards codification
ASU	accounting standards update
DD&A	depreciation, depletion and amortization
FASB	Financial Accounting Standards Board
FIFO	first-in, first-out
G&A	general and administrative
GAAP	generally accepted accounting principles
LIFO	last-in, first-out
NPNS	normal purchase normal sale
PP&E	properties, plants and equipment
VIE	variable interest entity

Miscellaneous

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

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,” “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 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 pa*ge 69.*

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 14 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. On December 31, 2021, we employed approximately 9,900 people worldwide and had total assets of about $91 billion. Total company production for the year was 1,567 MBOED.

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.

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 the 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) assets in the Delaware Basin. Assets acquired include approximately 225,000 net acres of producing properties located entirely in Texas. 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: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. For operating segment and geographic information, *see Note 23*.

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

The information listed below appears in the "Supplementary Data - 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 "Supplementary Data - Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements. Approximately 86 percent of our proved reserves are in countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six MCF of natural gas converts to one BOE. See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the following summary reserves table.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2021**	2020	2019
Crude oil			
Consolidated operations	**2,964**	2,051	2,562
Equity affiliates	**63**	68	73
Total Crude Oil	**3,027**	2,119	2,635
Natural gas liquids			
Consolidated operations	**644**	340	361
Equity affiliates	**33**	36	39
Total Natural Gas Liquids	**677**	376	400
Natural gas			
Consolidated operations	**1,523**	1,011	1,209
Equity affiliates	**617**	621	736
Total Natural Gas	**2,140**	1,632	1,945
Bitumen			
Consolidated operations	**257**	332	282
Total Bitumen	**257**	332	282
Total consolidated operations	**5,388**	3,734	4,414
Total equity affiliates	**713**	725	848
Total company	**6,101**	4,459	5,262

Alaska

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

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Greater Prudhoe Area	36.1 %	Hilcorp	67	16	12	85
Greater Kuparuk Area	89.2-94.7	ConocoPhillips	73	-	2	73
Western North Slope	100.0	ConocoPhillips	38	-	2	39
Total Alaska			178	16	16	197

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 conventional oil field in North America, is the site of a large waterflood and enhanced oil recovery operation, supported by a large gas and water processing operation. Prudhoe Bay's western satellite fields 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. Field installations include seven production facilities, two gas plants, two seawater plants and a central power station.

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

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

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. Field 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 Petroleum Reserve Alaska (NPR-A). In 2017, we began construction in the unit with two drill sites: Greater Mooses Tooth #1 (GMT-1) and Greater Mooses Tooth #2 (GMT-2). GMT-1 achieved first oil in 2018 and completed drilling in 2019. In 2021, the third and final construction season for GMT-2 was successfully completed, and drilling operations commenced during the second quarter. First oil for GMT-2 was achieved in the fourth quarter of 2021, as planned.

During 2021, we operated a conventional rotary rig and an extended reach drilling rig in the Western North Slope, 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 the NPR-A, was conducted in 2020. There was no appraisal activity in 2021. In August 2021, an Alaska federal judge vacated the U.S. government's approval granted to our planned Willow project previously approved by the BLM in October 2020. The Department of Justice did not appeal the decision and neither did we. We are actively supporting the BLM and Department of Interior as they conduct the Supplemental Environmental Impact Statement process to address issues highlighted by the federal district court. In the interim, we are continuing with FEED work in service of a final investment decision.

The Stony Hill 1 well located to the east of the Greater Mooses Tooth Unit within the NPR-A was plugged 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 federal lands. We are currently evaluating this seismic data for future exploration opportunities.

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

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
The Lower 48 segment consists of operations located in the 48 contiguous U.S. states and the Gulf of Mexico. The segment is organized into the Permian and Gulf Coast and Rockies business units with a portfolio of low cost of supply, short cycle time, resource-rich unconventional plays, and conventional production from legacy assets. Based on 2021 production volumes, the Lower 48 is the company's largest segment and contributed 55 percent of our consolidated liquids production and 64 percent of our consolidated natural gas production.

In 2021, we completed two acquisitions significantly increasing our Permian position in the Lower 48. On January 15, 2021, we completed the acquisition of Concho adding complementary acreage across the Delaware and Midland basins. On December 1, 2021, we completed the acquisition of Shell's Delaware Basin position adding significant Texas acreage in the Delaware Basin. The accounting close date used for reporting purposes of the Shell transaction was December 31, 2021. For additional information related to these acquisitions, *see Note 3*.

	2021			
	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production				
Delaware Basin	162	27	584	286
Midland Basin	89	9	229	136
Permian—Other	11	2	40	20
Total Permian	262	38	853	442
Eagle Ford	116	53	251	211
Bakken	59	16	117	94
Gulf Coast and Rockies—Other	10	3	119	33
Total Gulf Coast and Rockies	185	72	487	338
Total Lower 48	447	110	1,340	780

At December 31, 2021, we held 10.8 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 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 southeastern New 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 development of assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. Our major focus in 2021 included the following areas:

- Delaware Basin—We operated six rigs and two frac crews on average during 2021, resulting in 92 operated wells drilled and 95 operated wells brought online. Primarily as a result of our Concho acquisition, production increased in 2021 compared with 2020, averaging 286 MBOED and 79 MBOED, respectively.
- Midland Basin—We operated five rigs and two frac crews on average during 2021, resulting in 118 operated wells drilled and 102 operated wells brought online. Primarily as a result of our Concho acquisition, production increased in 2021 compared with 2020, averaging 136 MBOED and 6 MBOED, respectively.
- Eagle Ford—We operated four rigs and two frac crews on average in the Eagle Ford during 2021, resulting in 93 operated wells drilled and 160 operated wells brought online. Production increased in 2021 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, resulting in 6 operated wells drilled and 21 operated wells brought online. Production increased in 2021 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 48. In January 2022, we entered into an agreement to sell our interests in additional noncore assets in the Lower 48. This 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 Texas and New 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 liquids-rich Montney unconventional play in British Columbia. In 2021, operations in Canada contributed 8 percent of our consolidated liquids production and 4 percent of our consolidated natural gas production.

			2021				
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production							
Surmont	50.0 %	ConocoPhillips	-	-	-	69	69
Montney	100.0	ConocoPhillips	8	4	80	-	25
Total Canada			8	4	80	69	94

Surmont

Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called SAGD, whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. Operations include two central processing facilities for treatment and blending of bitumen. At December 31, 2021, we held 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. Surmont is a 50/50 joint venture with TotalEnergies SE that offers long-lived, sustained production. We are focused on 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 Recovery Unit constructed in Alberta, unlocking additional value for the asset by providing market access to our heavy crude oil.

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

Montney

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

In 2021, development activity consisted of drilling three horizontal wells and bringing 12 wells online. In 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. 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 Norwegian sector of the North Sea; the Norwegian Sea; Qatar; Libya; and terminalling operations in the U.K. In 2021, operations in Europe, Middle East and North Africa contributed 12 percent of our consolidated liquids production and 14 percent of our consolidated natural gas production.

Norway

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Greater Ekofisk Area	30.7-35.1 %	ConocoPhillips	49	2	41	58
Heidrun	24.0	Equinor	13	1	35	20
Aasta Hansteen	10.0	Equinor	-	-	84	14
Alvheim	20.0	Aker BP	9	-	13	11
Troll	1.6	Equinor	2	-	58	11
Visund	9.1	Equinor	2	1	46	11
Other	Various	Equinor	6	-	21	10
Total Norway			81	4	298	135

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. This project consisted of 8 wells that have all been completed and brought online as of May 2021. 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, 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 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.

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 for 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 Sea.

Exploration
In 2021, we prepared for a four well exploration and appraisal campaign to take place in 2022. Planned 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 additions, PL891B and PL1045B.

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

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

Qatar

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
QG3	30.0 %	Qatargas Operating Company Limited	13	8	373	83

QG3 is an integrated development jointly owned by QatarEnergy (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 QatarEnergy and 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

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Waha Concession	16.3 %	Waha Oil Co.	37	-	15	40

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

Asia Pacific

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

Australia

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	-	680	113

Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited (37.5 percent) and China Petrochemical Corporation (Sinopec) (25 percent), 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 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.

In December 2021, the company announced it has notified Origin Energy that it is exercising its preemption right to purchase an additional 10 percent shareholding interest in APLNG from Origin Energy for $1.645 billion, which will be funded from cash on the balance sheet and subject to customary adjustments. The effective date of the transaction is July 1, 2020 with closing anticipated to occur in the first quarter of 2022 subject to Australian government approval. There will be no change to the operational structure of the APLNG joint venture, whereby Origin Energy will remain the upstream operator of the natural gas production and pipeline system, and 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 operatorship of an offshore Exploration Permit (T/49P) located in the Otway Basin, Australia. We obtained an additional five percent interest, increasing our interest to 80 percent, in June 2020. A 3D seismic survey acquisition was completed in October 2021, and this data will be evaluated for future exploration opportunities.

Indonesia

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
South Sumatra	54 %	ConocoPhillips	2	-	294	51

During 2021, 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.

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

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

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 a 740-kilometer 2D seismic acquisition program. After completion of prospect evaluation, both PSC contractors decided to relinquish rights and return this block to the government. The relinquishment was approved by the government in August 2021.

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

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

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 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 platforms and a central processing platform. First production from Phase 3 was achieved in 2018. This project could include up to 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 achieved first production in 2020. This project could include up to 62 new wells, 14 of which have been completed and brought online as of December 2021.

On April 5, 2021, a fire occurred on the non-operated V platform in the Bohai Bay. On April 6, 2021, the fire was extinguished. We worked with the operator and implemented a recovery plan resulting in production resumption in December 2021.

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

Malaysia

			2021			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Gumusut	29.5 %	Shell	19	-	-	19
Malikai	35.0	Shell	13	-	-	13
Kebabangan (KBB)	30.0	KPOC	2	-	66	13
Siakap North-Petai	21.0	PTTEP	1	-	-	1
Total Malaysia			35	-	66	46

We have varying stages of exploration, development and production activities across approximately 2.7 million net acres in Malaysia, with working interests in six PSCs. Four of these PSCs are located in waters off the eastern Malaysian state of Sabah: Block G, Block J, the Kebabangan Cluster (KBBC), which we do not operate, and Block SB405, an operated exploration block acquired in 2021. We also operate another two exploration blocks, 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 Phase 2 first oil was achieved in 2019. Development drilling associated with Gumusut Phase 3, a four-well program, is planned 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 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 one of its markets. The pipeline operator has initiated repairs and is working toward pipeline testing during 2022.

Block G

Malikai

We hold a 35 percent working interest in Malikai. This field achieved first production in December 2016 via the Malikai Tension Leg Platform, ramping to peak production in 2018. The KMU-1 exploration well was completed and started producing through the Malikai platform in 2018. Malikai Phase 2 development first oil was achieved in February 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 was achieved in November 2021.

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 and appraisal drilling is planned for 2022.

In 2018, we were awarded a 50 percent working interest and operatorship of Block SK304 encompassing 2.1 million gross acres off the coast of Sarawak, offshore Malaysia. We acquired 3D seismic over the acreage and 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 Block SB405 encompassing 1.4 million gross acres off the coast of Sabah, offshore Malaysia. Acquisition of a 3D seismic survey over the acreage is planned for 2022.

Other International

The Other International segment includes activities in Colombia as well as contingencies 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 extending over approximately 67,000 net acres. 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. The blocks are currently in Force Majeure following a preliminary injunction temporarily suspending hydraulic fracturing activities.

Argentina

On September 16, 2021, ConocoPhillips Petroleum Holdings BV signed and closed the sale of shares in ConocoPhillips Argentina Holdings Sarl and ConocoPhillips Argentina Ventures SRL. With this transaction, 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 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 and Europe. 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, 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.

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 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 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. 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 OSROs including Oil Spill Response Limited, 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, increase recoveries from our legacy fields, improve the efficiency of our exploration program, produce heavy oil economically with less emissions and implement sustainability measures.

In early 2021, we established a multi-disciplinary Low Carbon Technologies organization to support the company's net-zero road map for scope 1 and 2 emissions, understand the new energies landscape, and prioritize opportunities for future competitive investment. Throughout 2021, we executed emissions reduction projects across our global portfolio including production efficiency measures and methane and flaring reductions. We also completed pre-development work to evaluate large scale wind energy opportunities to power our operations in the Permian, North Sea and Bohai Bay. Within the new energies landscape, the company has prioritized opportunities in CCUS and hydrogen. In 2021, CO2 storage sites were evaluated along the Texas and Louisiana Gulf Coast and we initiated activities to provide carbon capture and storage to industrial emitters. 2021 also saw early investments in enabling hydrogen technologies and we began evaluating hydrogen opportunities in both domestic and international markets.

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.

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 1.3 trillion cubic feet of natural gas and 159 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2030. We expect to fulfill these delivery commitments with third-party purchases, as supported by our gas management agreements; proved developed reserves; and PUDs. See the disclosure on "Proved Undeveloped Reserves" in the "Supplementary Data - Oil and Gas Operations" section following the Notes to Consolidated Financial Statements, for information on the development of PUDs.

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

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, NGLs and natural gas in an efficient, cost-effective manner. 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 (HCM) 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 of our internal and external stakeholders. In particular, we believe a safe organization is a successful organization, so we prioritize personal and process safety across the company. Our SPIRIT Values 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 HCM strategy and driving accountability for meaningful progress. The ELT and Board of Directors engage often on workforce-related topics. Our HCM 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. Our HCM programs are built around three pillars that we believe are necessary for success: a compelling culture, a world-class workforce and strong external 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 what we do and continuously find ways to do our jobs better. Together, we deliver strong performance, but not at all costs. We embrace our core cultural attributes that are shared by everyone, everywhere. With two significant acquisitions completed in 2021, we prioritized cultural integration. We seized the opportunity to learn from and value each other's cultures. This involved employee engagement, active listening and leveraging data analytics to monitor key workforce and engagement metrics.

Health, Safety and Environment

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

We continuously look for ways to operate more safely, efficiently and responsibly. We focus on reducing human error by emphasizing interaction among people, equipment and work processes. By being curious about how work is done, recognizing error-likely situations and applying safeguards, we can reduce the likelihood and severity of unexpected incidents. We conduct thorough investigations of all serious incidents to understand the root cause and share lessons learned globally to improve our procedures, training, maintenance programs and designs. Through this culture of continuous learning and improvement, we continue to refine our existing HSE 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 the early pandemic stages: protect our employees and contractors, mitigate the spread of COVID-19 and safely run the business. We have pursued these priorities via a coordinated crisis management support team, frequent workforce communications and flexible programs to suit the challenging environment. Our office and field staffs adhered to rigorous mitigation protocols implemented across our operations utilizing the most current guidance from health authorities. Mitigation measures, including requirements for remote work, vaccines and testing were driven by the specific situations applicable to a region or business function. These measures proved effective at lessening the impact to our employees and contractors, mitigating the spread of COVID-19 and minimizing the potential for business disruption.

Diversity, Equity and Inclusion (DEI)

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

The ELT has ultimate accountability for advancing our DEI commitment through a governance structure that includes an ELT-level DEI Champion, a global DEI Council consisting of senior leaders from across the company and organization-wide DEI goals. The company sets goals and measures progress based on three pillars that guide our DEI activities: leadership accountability, employee awareness and processes and programs. In addition, our DEI plans and 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 employee survey and prioritized action plans tied to employee sentiment. 2021 accomplishments included:

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

We actively monitor diversity metrics on a global basis. In 2021, we expanded our internal and external workforce metrics and HCM disclosures, including publishing our 2018-2020 Consolidated EEO-1 Reports and our inaugural HCM report. Tables of 2021 employee demographics by gender and ethnicity, and by country, are shown 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 Total**
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 combination of work from both office and home. The HOW program blends the advantages of in-person engagement with individual flexibility for eligible employees where a hybrid schedule is feasible. The design of the U.S. program was adopted in many of our global locations.

A World-Class Workforce

Our HCM approach addresses programs and processes necessary for ensuring we have an engaged workforce with the skills to meet our business needs. We take a holistic view of HCM that addresses each of the critical 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 skills, in the right places, to achieve our strategic objectives. We offer university internships across multiple disciplines to attract the best early-career talent. We partner with top diversity organizations and universities, including Hispanic-serving organizations and historically black colleges and universities. We also recruit experienced hires to fill critical skills and maintain a broad range of expertise and experience. We conduct routine talent assessments with leaders to ensure we have the organizational capacity and capabilities to execute our business plans. We have taken significant steps to embed inclusion into each step of our recruiting practices, including adapting the way we construct job descriptions to using intentionally diverse interview panels.

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

2021 Hiring & Attrition Metrics	Percent of Total
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 employees to build diverse and fulfilling careers with ConocoPhillips. Our workforce is trained through a combination of on-the-job 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 future 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 "how" rating to assess behaviors to ensure they align with our SPIRIT Values.

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

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

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 the frontline worker, every employee participates in VCIP, our annual incentive program, which aligns employee 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 needs of their families. We provide flexible work schedules and competitive time off, including parental leave policies in many locations. In 2021, we enhanced our programs to provide expanded coverage for families requiring disability support, elder care and childcare. We also provide access to quality childcare, including onsite child care, where access locally is a challenge.

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 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 compensation programs and policies. As part of the analysis, we considered the performance measures we use as well as the different types of compensation, varied performance measurement periods and extended vesting schedules that we utilize under each incentive compensation program. As a result of this review, management concluded that the risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on the company. As part of the Board of Directors' oversight of our 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 the risks arising from our compensation 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 involvement in local charitable activities through employee giving programs that include United Way campaigns, matching gift contributions and volunteer grants.

While we have been recognized for our ESG and DEI efforts, we know that it takes ongoing commitment to make sustainable progress; therefore, we continue to provide training, build awareness and reinforce accountability at all levels of the organization and focus on behaviors and processes that build an environment in which 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, including 438 active U.S. patents. During 2021, we received 40 patents in the U.S. and 45 foreign patents. Our products and processes generated licensing revenues of $65 million related to activity in 2021. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 58 through 63 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs 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 website is not part of this report on Form 10-K.

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

Item 1A. Risk Factors

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. These risk factors are not the only risks we face. Our business could also be affected by additional risks and uncertainties not currently known to us or that we currently consider to be immaterial. If any of these risks 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 adversely affected.

Risks Related to Our Industry

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

The oil and gas business is a commodity business. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for crude oil, bitumen, natural gas and NGLs. Such prices can fluctuate widely depending upon global events or conditions that affect supply and demand, most of which are out of our control. In early 2020 global oil demand decreased precipitously alongside global COVID-19 economic shutdowns. Although global oil demand and global oil prices improved through 2021, the global economic recovery remains uncertain. 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 and NGL prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity, and may also affect the amount of dividends we elect to declare and pay on our common stock and the amount of shares we elect to acquire as part of the share repurchase program and the timing of such acquisitions. Lower prices may also limit the amount of reserves we can produce economically, thus 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. Prolonged depressed 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 and NGL 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 7*. If commodity prices decrease relative to their current levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we could incur future impairments to long-lived assets used in operations, investment 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 or estimated change to our unit-of-production rates at this time, our results of operations could be 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. Over the course of the pandemic, public health officials 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, others have been reinstated in areas that have experienced a resurgence of COVID-19 cases and there is no guarantee restrictions will not be reimposed in the future. Despite the increased availability of vaccines in certain jurisdictions, the COVID-19 pandemic may continue or worsen during the upcoming months, including as a result of the emergence of more infectious variants of the virus, vaccine hesitancy or increased business and social activities, which may cause governmental authorities to reinstate restrictions. As a result, the ongoing 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 effectiveness of vaccines or other treatments, and how quickly and to what extent economic conditions 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 pandemic. These impacts could include but are not limited to:

- Reduced demand for our products as a result of reductions in travel and commerce, whether related to mandated restrictions or otherwise;
- Disruptions in our supply chain due in part to scrutiny or embargoing of shipments from infected areas or invocation of force majeure clauses in commercial contracts due to restrictions imposed as a result of the global response to the pandemic;
- Failure of third-parties on which we rely, including our suppliers, contract manufacturers, contractors, 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;
- Increased challenges in retention of personnel caused by vaccine hesitancy and the resistance of some in our workforce to comply with workplace protocols necessary to ensure the health and safety of our workforce and minimize disruptions to the business, such as vaccine and testing requirements, or the use of personal protective equipment; 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 foreseeable, could materially increase our costs, negatively impact our revenues and damage our financial condition, results 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 develop resources, the scope of our business will decline, resulting in an adverse impact to our business.

As we produce crude oil and natural gas from our existing portfolio, the amount of our remaining reserves declines. If we are not successful in replacing the crude oil and natural gas we produce with good prospects for future organic opportunities or through acquisitions, our business will decline. In addition, our ability to successfully develop our reserves is dependent on a number of factors, including our ability to obtain and renew rights to develop and produce hydrocarbons; our success at reservoir optimization; our ability to bring long-lead time, capital intensive projects to completion on budget and on schedule; and our ability to efficiently and profitably operate mature properties. If we are not successful in developing the resources in our portfolio, 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 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 crude oil, bitumen, natural gas and NGLs in an efficient, cost-effective manner. We must compete for the materials, equipment, services, employees and other personnel (including geologists, geophysicists, engineers and other specialists) necessary to conduct our business. Some of our competitors are larger and have greater resources than we do, or may have established strategic long-term positions or strong governmental or other relationships in countries or areas in which we operate, or may be willing to incur a higher level of risk than we are willing to incur to obtain potential sources of supply. As a consequence, we may be at a competitive disadvantage in certain respects, such as in accessing the necessary materials, equipment, services, resources and personnel. In addition, we may be at a competitive disadvantage when competing with state-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 financial condition and results of operations may be adversely affected.

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

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

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

As discussed 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 of crude oil, bitumen, natural gas and NGL wells below actual production capacity. Similarly, in response to increased domestic energy costs, circumstances determined to be in the economic interest of the country, or a declared national emergency, the U.S. government could restrict the export of our products which would adversely impact our domestic business. Because legal requirements are frequently changed and subject to interpretation, we cannot predict whether future restrictions on our business may be enacted or become applicable to us.

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

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

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

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, product spills, severe weather, geological events, labor disputes, geopolitical tensions, armed hostilities, terrorist or piracy attacks, sabotage, civil unrest or cyberattacks. Our operations are subject to the additional hazards of pollution, toxic substances and other environmental hazards and risks. Offshore activities may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. 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. 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.

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, which 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 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, 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 emissions, including methane;
- Carbon taxes;
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes;
- The dismantlement, abandonment and restoration of historic properties and facilities at the end of their useful lives; and
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and unconventional plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. In addition, to the extent these expenditures are assumed by a buyer as a result of a disposition, it may result in our incurring substantial costs if the buyer is unable to satisfy these obligations. 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 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 and pending international agreements and national, regional or local legislation and regulatory measures to limit GHG emissions, such as cap and trade regimes, specific emission standards, carbon taxes, restrictive permitting, increased fuel efficiency standards and incentives or mandates for renewable energy. Although we may support many of these legislative and regulatory measures, how and when they are enacted could result in a material adverse effect to our business, financial condition, results of operations and cash flows in future periods.

For example, in November 2021, the U.S. Environmental Protection Agency published a Proposed Rule that would revise the regulations governing the emission of GHG and volatile organic compounds from new oil and gas production facilities, and emission guidelines for states to use when revising Clean Air Act implementation plans to limit GHG emissions from existing oil and gas facilities. Although the company supports the direct federal regulation of methane from new and existing sources, the final form and substance of any regulations are not currently known and could result in additional capital expenditures and compliance, operating and 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 of the Parties (COP26). At the conclusion of COP26, the U.S. and nearly 200 other counties agreed to the Glasgow Climate Pact, committing to revisiting and strengthening their current emissions targets to 2030 in 2022 and finalizing the outstanding elements of the Paris Agreement. In addition, our operations continue in countries around the world which are party to the Paris Agreement. The implementation of current agreements and regulatory measures, as well as any future agreements or measures addressing climate change and GHG emissions, may adversely impact the demand for our products, impose taxes on our products or operations or require us to purchase emission credits or reduce emission of GHGs from our operations. As a result, we may experience declines in commodity prices or incur substantial capital expenditures and compliance, operating, maintenance and remediation costs, any of which may have an adverse effect on our business and results of operations.

In September 2021, we announced an improvement to our Paris-aligned climate risk framework, whereby we committed to an improvement to our targets for reducing our scope 1 and 2 emissions intensity on both a gross operated and net equity basis and reaffirmed our commitment to advocate for the reduction of scope 3 emissions 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 us to purchase emission credits, or limit or impact our business plans. If we are not successful in select internal initiatives, we may be adversely affected and potentially need to reduce economic end-of-field life of certain assets and impair associated net book value.

Increasing attention to global climate change has also resulted in pressure from and 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, Harvard University announced in September 2021 that it will stop investing its $42 billion endowment in fossil fuels and will let its current investments expire without renewal. As public pressure continues to mount, our access to capital on terms we find favorable (if it is available at all) may be limited and our costs may increase, our reputation could be damaged 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 affect 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 the future. We could also receive lawsuits alleging a failure or lack of diligence to meet our publicly stated ESG goals, so called “greenwashing” cases.

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 and supply chain could be adversely impacted, and demand for our products could fall.

For more information on legislation or precursors for possible regulation relating to global climate change that affect or could affect our operations and a description of the company’s response, *see the “Contingencies—Climate Change” section of Management’s Discussion and Analysis of Financial Condition and Results of Operations*.

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

Actions of the U.S., state, local and foreign governments, through sanctions, tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the U.S. and abroad. In certain locations, restrictions on our operations; leasing restrictions; 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 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 state 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. In addition, we may face regulatory changes in the U.S. including, but not limited to, the enactment of tax law changes that adversely affect the fossil fuel industry, new methane emissions standards, restrictive flaring requirements, and more stringent environmental impact studies and reviews. 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 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 safely for many decades, a number of new laws, regulations and permitting requirements are under consideration which could result in increased costs, operating restrictions, operational 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.

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 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 policies and regulations may affect our ability to collect payments such as those pertaining to the settlement with Petróleos de Venezuela, S.A. (PDVSA) or the ICSID Award against the Government of Venezuela; or to obtain or maintain licenses or permits, including those necessary for drilling and development of wells 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 38 percent of our hydrocarbon production was derived from production outside the U.S. in 2021, and 29 percent of our proved reserves, as of December 31, 2021, were located outside the U.S. We are subject to risks associated with operations in both domestic and international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, NGLs or LNG pricing and taxation, other political, economic or diplomatic developments (including the macro effects of international trade policies and disputes), potentially disruptive geopolitical conditions, and international monetary and currency rate fluctuations. Restrictions on production of oil and gas could increase to the extent governments view such measures as a viable approach for pursuing national and global energy and climate policies. In addition, some countries where we operate lack a fully independent judiciary system. This, coupled with changes in foreign law or policy, results in a lack of legal certainty that exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

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 on acceptable terms or at all. In addition, although we anticipate we will be able to repay our existing indebtedness when it matures or in accordance with our stated plans, there can be no assurance we will be able to do so. Our ability to obtain additional financing or refinance our existing indebtedness when it matures or in accordance with our plans, will be subject to a number of factors, including market conditions, our operating performance, investor sentiment and our ability to incur additional debt in compliance with agreements governing our then-outstanding debt. If we are unable to generate sufficient funds from operations or raise additional capital for any reason, our business could be adversely affected.

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

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

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

Our ability to execute our capital return program is subject to certain considerations.

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

Ordinary 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; and
- Other factors our Board of Directors deems relevant.

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

- The anticipated level of distributions required to meet our capital returns commitment;
- 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 addition, based on the current environment, we anticipate also paying a quarterly VROC to our shareholders staggered from the ordinary dividend payment, resulting in up to eight cash distributions to shareholders throughout the year; however, the amount of the VROC is variable and will depend upon the above factors, and our Board of Directors may determine not to pay a VROC in a quarter or may cease declaring a VROC at any time. In addition, our Board of Directors may reduce our ordinary dividend or cease declaring dividends at any time, including if it determines that our net cash provided by operating activities, after deducting capital expenditures and investments, are not sufficient to pay our desired levels of dividends to our stockholders or to pay dividends to our stockholders at all.

Additionally, as of December 31, 2021, $10.9 billion of repurchase authority remained of the $25 billion share repurchase program our Board of Directors had authorized. Our share repurchase program does not obligate us to acquire a specific number of shares during any period, and our decision to commence, discontinue or resume repurchases in any period will depend on the same factors that our Board of Directors may consider when declaring dividends, among others. In the past we have suspended our share repurchase program in response to market downturns, including as a result of the oil market downturn that began in early 2020, and we may do so again in the future.

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

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

We regularly review our portfolio and pursue growth through acquisitions and seek to divest noncore assets or businesses. We may not be able to complete these transactions on favorable terms, on a timely basis, or at all. 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 risk of impairment; (ii) the inability to dispose of noncore assets and businesses on satisfactory terms and conditions; and (iii) 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, including environmental liabilities, or with regard to divested assets or businesses, claims by purchasers to whom we have provided contractual indemnification.

In addition, we may face difficulties in integrating the operations, technologies, products and personnel of any acquired assets or businesses. For example, we completed two major acquisitions in 2021, including the acquisition of Concho in January and the acquisition of the Shell Permian assets in December. Combined, these transactions added approximately 800,000 net acres, thereby significantly increasing our unconventional position and operations in the Permian. We may still encounter difficulties integrating the acquired assets into our business. There are a large number of processes, policies, procedures, operations and technologies and systems that must be integrated in connection with the transactions and the integration of the acquired assets. It is possible that the integration process could result in the disruption of our ongoing business; inconsistencies in standards, controls, procedures and policies; unexpected integration issues; higher than expected integration costs and an overall post-completion integration process that takes longer than originally anticipated. We have been and will be required to devote management attention and resources to integrating the business practices and operations. Any delays encountered in the integration process could have an adverse effect on our revenues or on our level of expenses or capital investment and operating results, which may adversely affect the value of our common stock. In addition, the actual integration may result in additional and unforeseen expenses. Although we expect that the strategic benefits, and additional income, as well as the realization of other efficiencies related to the integration of the acquired assets, may offset incremental transaction-related costs over time, if we are not 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 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 cybersecurity 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, including third-party cloud and IT service providers) corrupted or unusable, threats to the security of our facilities and infrastructure as well as those of third-parties with whom we do business, including third-party cloud and IT service providers, 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 cyberattack of these operating systems, or of the networks, software 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, make it difficult or impossible to accurately account for production and settle transactions, or negatively impact public health or safety, economic security, or national security.

Although we have experienced occasional cybersecurity incidents, none have had a material effect on our business, operations or reputation. As cyberattacks have continued to evolve, we have become subject to new government-imposed security requirements to implement specific mitigation measures to protect against ransomware attacks and other known threats to information and operations technology. In response, 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 reasonable security 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 completely 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, litigation exposure and legal liability or regulatory fines, penalties or intervention. In addition, we have exposure to cybersecurity incidents and the negative impacts of such incidents related to our data and proprietary information housed on third-party IT systems, including the cloud. Any of these could materially and adversely affect our business, results of operations or financial condition, and any of the foregoing can be exacerbated by a delay or failure to detect a cybersecurity incident or the full extent of such incident notwithstanding reasonable security procedures and controls. The prevalence of remote working during the pandemic has introduced additional cybersecurity risk. 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 completely 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

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business, 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. *See Note 11* for a description of such legal and administrative proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

Information about our Executive Officers

Name	Position Held	Age*
William L. Bullock, Jr.	Executive Vice President and Chief Financial Officer	57
Kontessa S. Haynes-Welsh	Chief Accounting Officer	47
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	59
Timothy A. Leach	Executive Vice President, Lower 48	62
Andrew D. Lundquist	Senior Vice President, Government Affairs	61
Dominic E. Macklon	Executive Vice President, Strategy, Sustainability and Technology	52
Nicholas G. Olds	Executive Vice President, Global Operations	52
Kelly B. Rose	Senior Vice President, Legal, General Counsel	55
Heather G. Sirdashney	Vice President, Human Resources and Real Estate and Facilities Services	49

**On February 17, 2022.*

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 10, 2022. Set forth below is information about the executive officers.

William L. Bullock, Jr. was appointed Executive Vice President and Chief Financial Officer as of September 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.

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

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.

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 to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

Dominic E. Macklon was appointed Executive Vice President, Strategy, Sustainability and Technology in September 2021, having previously served as Senior Vice President, Strategy, Exploration and Technology since August 2020. Prior to that, he served as President, Lower 48 from June 2018 to August 2020, Vice President, Corporate Planning & Development from January 2017 to June 2018, and President, U.K. from September 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 Executive Vice President, Global Operations as of August 2021, having previously served as Senior Vice President, Global Operations since August 2020. Prior to that, he served as Vice President, Corporate Planning & Development from June 2018 to August 2020, Vice President, Mid-Continent Business Unit, Lower 48 from September 2016 to June 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 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.

Heather G. Sirdashney was appointed Vice President, Human Resources and Real Estate and Facilities Services in March 2021, having previously served as Vice President, Human Resources from January 2019. Prior to that, she served in other leadership roles including Human Resources General Manager, Human Resources Business Partner Manager, Lower 48, and Director of Human Resources Shared Services.

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	
	2021	2020
First	$ **0.430**	0.420
Second	**0.430**	0.420
Third	**0.430**	0.420
Fourth	**0.460**	0.430
Number of Stockholders of Record at January 31, 2022*		38,099

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

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

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, 2021	6,100,833	$ 73.36	6,100,833	$ 11,811
November 1-30, 2021	6,367,204	73.42	6,367,204	11,344
December 1-31, 2021	6,751,987	71.65	6,751,987	10,860
	19,220,024	$	19,220,024	

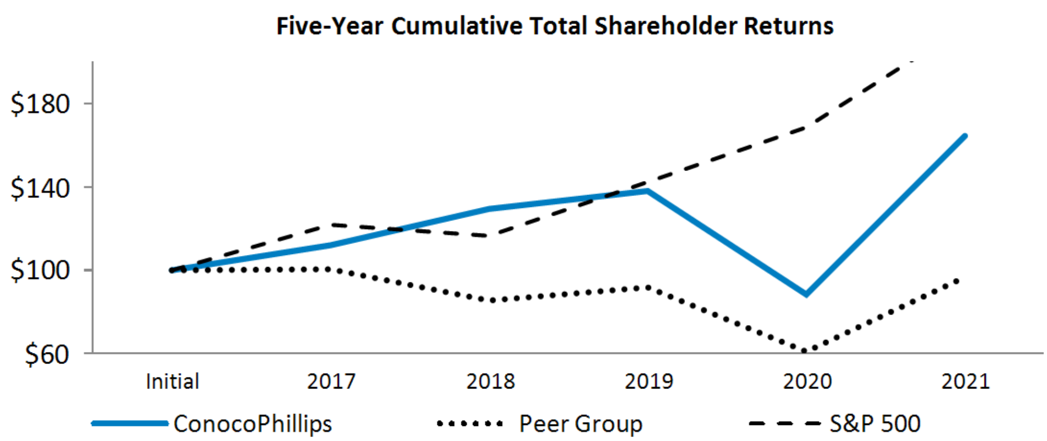
** There were no repurchases of common stock from company employees in connection with the company's broad-based employee incentive plans.*

In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. As of December 31, 2021, we had repurchased $14.1 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. For more information *see "Item 1A—Risk Factors – Our ability to execute our capital return program 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, 2016 to December 31, 2021. 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 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.

The comparison assumes $100 was invested on December 31, 2016, 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.



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," "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 OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 69.

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 one of the world's leading E&P companies based on both production and reserves with operations and activities in 14 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. Headquartered in Houston, Texas, at December 31, 2021, we employed approximately 9,900 people worldwide and had total assets of $91 billion.

Completed Acquisitions

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 in an all-stock transaction for $13.1 billion. *See Note 3*.

In December 2021, we completed our acquisition of Shell Enterprises LLC's (Shell) assets in the Delaware Basin in an all-cash transaction for $8.7 billion after customary adjustments. Assets acquired include approximately 225,000 net acres of producing properties located entirely in Texas. *See Note 3. See Item 1A "Risk Factors" for 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 reaching pre-pandemic levels in the second half of the year; however, we expect prices will continue to be cyclical and volatile. Our view is that a successful business strategy in the E&P industry must be resilient in lower price environments while also retaining upside during periods of higher prices. As such, we are unhedged, remain highly disciplined in our investment decisions and continually monitor market fundamentals, including OPEC Plus updates regarding supply guidance and inventory levels. Although global oil demand improved through 2021, the global economic recovery remains uncertain and subject to various risk factors, including actions taken to stem the proliferation of COVID-19.

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

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

In 2021, we successfully delivered on our priorities. Total company production was 1,567 MBOED yielding cash provided by operating activities of $17 billion. We invested $5.3 billion into the business in the form of capital expenditures and provided returns of capital to shareholders of approximately $6 billion through our ordinary dividend and share repurchases. For 2021, our ordinary dividend returned $2.4 billion which included an increase from 43 cents per share to 46 cents per share, effective in December. Share repurchases resumed in February and amounted to $3.6 billion inclusive of our paced monetization program related to the Cenovus Energy (CVE) common shares owned. *See Note 5*. We also demonstrated our commitment to preserving our top-tier balance sheet with an announcement to reduce the company's gross debt by $5 billion over five years through a combination of natural and accelerated maturities.

As part of our ongoing portfolio high-grading and optimization efforts, in December 2021, we announced two transactions in our Asia Pacific segment enhancing our diverse portfolio. This included notifying Origin Energy of our intent to exercise our preemption right to purchase an additional 10 percent shareholding interest in APLNG for $1.645 billion, before customary adjustments, and the sale of our interests in Indonesia for approximately $1.4 billion before customary adjustments. In addition to those transactions, in January 2022, we entered into a divestiture agreement to sell our interest in noncore assets within our Lower 48 segment for $440 million. These transactions are expected to close in the first half of 2022. For more information on APLNG, *see Note 4* and for 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-end 2023, with approximately $2 billion sourced from the Permian Basin. As of year-end 2021, we have generated $0.3 billion in disposition proceeds. The proceeds from these transactions will be used in accordance with the company's 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. This framework is structured to continue delivering a compelling, growing ordinary dividend and through-cycle share repurchases. It includes the addition of a VROC tier. The VROC tier will provide a flexible tool for meeting our commitment of returning greater than 30 percent of cash from operating activities during periods where commodity prices are meaningfully higher than our planning price range. We have set our expected 2022 total return of capital from all three tiers at approximately $8 billion. *For more information on our three-tier return of capital framework, see Capital Resources and Liquidity*.

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

- Net-zero ambition for operational (scope 1 and 2) emissions by 2050 with active advocacy for a price on carbon to address end-use (scope 3) emissions;
- Targeting a reduction in gross operated and net equity operational GHG emissions intensity by 40 to 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 baseline, in addition to the 65 percent reduction we have made since 2015;
- Adding continuous methane detection devices to our operations, with an initial focus on the larger Lower 48 facilities;
- Dedicated low carbon technology organization responsible for identifying and prioritizing global emissions reduction initiatives and opportunities associated with the energy transition, CCUS and hydrogen; and
- ESG performance factoring into executive and employee compensation programs.

To support this commitment, in December 2021, we announced that approximately $0.2 billion of our 2022 company-wide capital expenditures would be dedicated to energy transition efforts across the company's global operations aimed at accelerating the reduction of the company's scope 1 and 2 emissions and to pursue business opportunities that address end-use emissions and early-stage low-carbon technology opportunities that leverage the company's adjacencies.

Operationally, we remain focused on safely executing the business. Production increased 440 MBOED or 39 percent in 2021, compared to 2020. Production excluding Libya for 2021 was 1,527 MBOED. After adjusting for closed acquisitions and dispositions, impacts from 2020 curtailments, 2021 Winter Storm Uri and the conversion of Concho two-stream contracted volumes to a three-stream basis, production increased by 28 MBOED or 2 percent. This increase was primarily due to new production from the Lower 48 and other development programs across the portfolio, partially offset by normal field decline. Production from Libya averaged 40 MBOED in 2021.

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 total of $8 billion, 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 ahead of schedule; acquired Shell's Permian assets on December 1, 2021;
- Exercised preemption right to purchase an additional 10 percent shareholding interest in APLNG, expected to close in the first quarter of 2022;
- Generated $0.3 billion in disposition proceeds from noncore sales and entered into agreements to sell an additional $1.8 billion in assets, subject to customary closing adjustments;
- Delivered strong operational performance across the company's asset base, resulting in full-year production of 1,527 MBOED, excluding Libya;
- Achieved first production from GMT2, Malikai Phase 2, SNP Phase 2; completed Tor II project and started production from a third Montney multi-well pad;
- Net cash provided by operating activities was $17 billion, exceeding capital expenditures and investments of $5.3 billion;
- Distributed $6.0 billion to shareholders through $2.4 billion in dividends and $3.6 billion of share repurchases, representing over 30 percent return of cash provided by operating activities to shareholders;
- Ended the year with cash and cash equivalents of $5.0 billion and short-term investments of $0.4 billion, totaling over $5.4 billion in ending cash and cash equivalents and short-term investments;
- Initiated a paced monetization of the company's CVE investment, generating $1.1 billion in proceeds through the sale of 117 million shares, with the funds applied to share repurchases; 91 million CVE shares remained outstanding at year-end 2021; and
- Advanced the company's net-zero ambition by announcing an increase in scope 1 and 2 GHG emissions-intensity reduction targets to 40 to 50 percent from a 2016 baseline on a net equity and gross operated basis by 2030, from the previous target of 35 to 45 percent on only a gross operated basis.

Business Environment

Brent crude oil prices averaged $71 per barrel in 2021, compared with $42 per barrel in 2020. The energy industry has periodically experienced this type of volatility due to fluctuating supply-and-demand conditions and such volatility may persist in the 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 financial principles that underpin our value proposition; balance sheet strength, peer leading distributions, disciplined investments and ESG excellence, all of which support strong financial returns.

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

- **Peer leading distributions.** We believe in delivering value to our shareholders via our three-tiered return of capital framework, which consists of a growing, sustainable dividend, share repurchases, and beginning in 2022, the addition of VROC. In 2021, we paid dividends on our common stock of approximately $2.4 billion and repurchased $3.6 billion of our common stock partially sourced from our paced monetization program related to the CVE common shares owned. Our combined dividends and repurchases represented over 30 percent of our net cash provided by operating activities. Our first VROC of $0.20 cents per share was paid on January 14, 2022, to shareholders of record as of January 3, 2022. Our VROC will be made at the Board of Director's discretion, subject to market conditions and other factors. *See Note 5*. *See "Item 1A—Risk Factors Our ability to execute our capital return program is subject to certain considerations."*

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

    - **Exercise 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 when an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to 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 overall 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, cost of carbon, price-related inflation and G&A. In setting our capital plans, we exercise a rigorous approach that evaluates projects using these 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 provide returns of capital to shareholders.

    - **Control our costs.** Controlling operating and overhead costs, without compromising safety or environmental stewardship, is a high priority. Using various methodologies, we monitor these costs monthly, on an absolute-dollar basis and a per-unit basis and report to management. 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 positively impacts our ability to deliver strong cash from operations.

    - **Optimize our portfolio.** In 2021, we completed the acquisition of Concho and Shell's Permian assets, significantly increasing our unconventional portfolio with many additional years of low cost of supply inventory. The addition of this highly complementary acreage in the Midland and Delaware basins created a sizeable Permian presence to augment our leading unconventional positions in the Eagle Ford and Bakken in the Lower 48. In our Asia Pacific segment, we notified Origin Energy of our intent to exercise our preemption right to purchase an additional 10 percent shareholding interest in APLNG and announced the sale of our interests in Indonesia. *See Note 3*.

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

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

      As required by current authoritative guidelines, the estimated future date when an asset will reach the 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 377 percent in 2021, reflecting a net increase from purchases and sales as well as higher prices. Our organic reserve replacement, which excluded a net increase of 1,115 MMBOE from sales and purchases, was 189 percent in 2021.

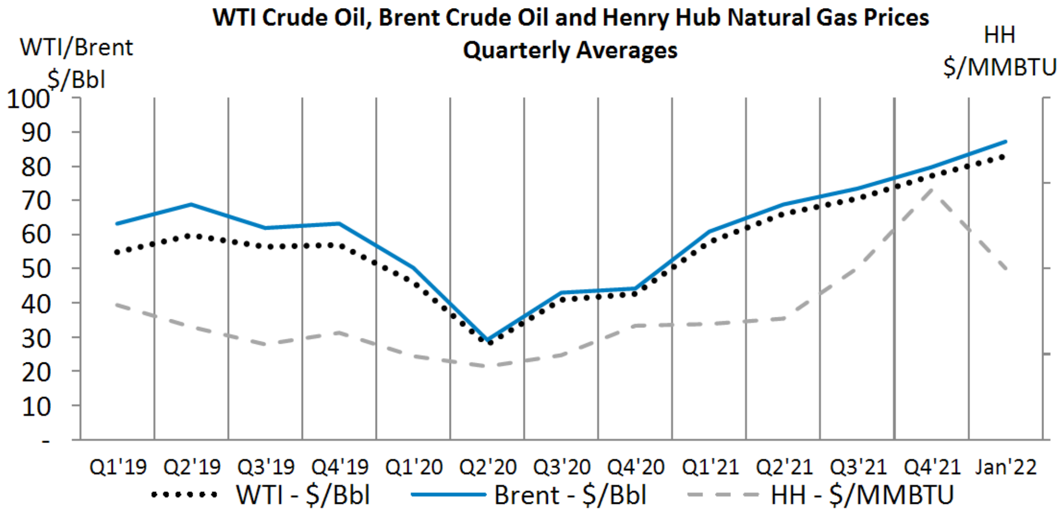
In the three years ended December 31, 2021, our reserve replacement was 155 percent. Our organic reserve replacement during the three years ended December 31, 2021, which excluded a net increase of 1,022 MMBOE related to sales and purchases, was 88 percent.

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 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 fully replace our production over subsequent years.

- **ESG Leadership.** Safety and environmental stewardship, including the operational integrity of our assets, remain our highest priorities. 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 the local and global environment and systematically manage risk to drive sustainable business operations. In September 2021, we reaffirmed and improved upon our commitment to ESG leadership and excellence and the specific targets that we set in October 2020 when we became the first U.S. based oil and gas company to adopt a Paris-aligned climate-risk strategy. Our comprehensive energy transition strategy is designed to sustainably meet global energy demand while delivering competitive returns on and of capital through the energy transition. Our strategy also recognizes the importance of reducing society's end-use emissions to meet global climate goals. As an E&P company, active only in the upstream side of the business, we do not produce end-use products directly for consumers. We believe that if everyone addressed their scope 1 and 2 emissions, scope 3 would also be addressed. This is why we have consistently taken a prominent role in advocating that scope 3 emissions be addressed through a well-designed economywide price on carbon. In addition, we are making early-stage investments in transition opportunities with the potential to generate competitive returns that will help address end-use emissions, including CCUS and Hydrogen. We are also engaging with 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 with crude oil and natural gas commodity prices. Commodity price levels are subject to factors external to the company and over which we have no control, including but not limited to global economic health, supply disruptions or fears thereof caused by civil unrest or military conflicts, actions taken by OPEC Plus and other producing countries, environmental laws, tax regulations, governmental policies, global pandemics 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 over the past three years:



Brent crude oil prices averaged $70.73 per barrel in 2021, an increase of 70 percent compared with $41.68 per barrel in 2020. Similarly, WTI crude oil prices increased 72 percent from $39.37 per barrel in 2020 to $67.92 per barrel in 2021. Following COVID-19 economic shutdowns in early 2020, global oil demand increased steadily through the year alongside the global economic recovery. OPEC Plus supply restraint, capital discipline by U.S. E&P's and various unplanned supply disruptions in producing countries moderated supply growth, reducing excess global inventories and putting upward pressure on global oil prices.

Henry Hub natural gas prices increased 85 percent from an average of $2.08 per MMBTU in 2020 to $3.85 per MMBTU in 2021. Extreme weather events in many parts of the world and several global LNG liquefaction outages depleted global natural gas inventories in early 2021, generating strong 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 barrel in 2020 to $37.52 per barrel in 2021. The increase was largely driven by strength in WTI, reflective of increasing global demand and OPEC discipline. The WCS differential to WTI at Hardisty remained fairly flat as record high production offsets incremental pipeline capacity. 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 increased 70 percent from $32.15 per BOE in 2020 to $54.63 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 resource scarcity to one of abundance. In recent years, the use of hydraulic fracturing and horizontal drilling in unconventional formations has led to increased industry actual and forecasted crude oil and natural gas production in the U.S. Although providing significant short- and long-term growth opportunities for our company, the increased abundance of crude oil and natural gas due to development of unconventional plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; and delay of plans to develop areas such as unconventional fields. Should one or more of these events occur, our revenues would be reduced, and additional asset impairments might be possible.

- **Impairments**. We participate in a capital-intensive industry. At times, our PP&E and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, a decision to dispose of an asset leads to a write-down to its fair value, or the current fair value of an investment is less than its carrying amount and the loss in value is deemed other than temporary. 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 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 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 civil unrest or strained relationships with governments that may impact our operations or investments. These changing environments could negatively impact our results of operations, and further changes to increase government fiscal take could have a negative impact on future operations. Our management carefully considers the fiscal and regulatory environment when evaluating projects or determining the levels and locations of our activity.

Outlook

Production and Capital

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

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

Operating Segments

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 incurred on the early retirement of debt, corporate overhead, certain technology activities, as well as licensing revenues.

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

Results of Operations

This section of the Form 10-K discusses year-to-year comparisons between 2021 and 2020. For discussion of year-to-year comparisons between 2020 and 2019, see "Management's Discussion and Analysis of Financial 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 segment follows:

		Millions of Dollars		
Years Ended December 31		**2021**	2020	2019
Alaska	$	**1,386**	(719)	1,520
Lower 48		**4,932**	(1,122)	436
Canada		**458**	(326)	279
Europe, Middle East and North Africa		**1,167**	448	3,170
Asia Pacific		**453**	962	1,483
Other International		**(107)**	(64)	263
Corporate and Other		**(210)**	(1,880)	38
Net income (loss) attributable to ConocoPhillips	$	**8,079**	(2,701)	7,189

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

- Higher realized commodity prices.
- Higher sales volumes primarily due to our Concho acquisition and absence of production curtailments. *See Note 3*.
- A gain of $1,040 million after-tax on our Cenovus Energy (CVE) common shares in 2021, as 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 carrying value of capitalized undeveloped leasehold costs related to our Alaska North Slope Gas asset.
    - Lower dry hole expenses.
    - Absence of early cancellation of our 2020 winter exploration program in Alaska.
    - Absence of unproved property impairment and dry hole expenses in 2020 for the Kamunsu East 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 segments.
- An after-tax gain of $194 million recognized for a FID bonus associated with our Australia-West divestiture in 2020. *See Note 3*.
- Lower impairments, primarily due to the absence of impairments recognized in 2020 for noncore assets in our Lower 48 segment partially offset by an impairment in our APLNG investment included within 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, primarily due to higher sales volumes.
- Higher DD&A expenses caused by higher production volumes, partially offset by lower rates driven from positive reserve revisions due to higher commodity prices in 2021.
- Absence of a $597 million after-tax gain on our Australia-West divestiture completed in May 2020.
- Restructuring and transaction expenses of $341 million after-tax associated with the Concho and Shell acquisitions in addition to mark-to-market impacts on certain key employee compensation programs.

- Realized losses on hedges of $233 million after-tax related to derivative positions assumed through our Concho acquisition. These derivative positions were settled entirely within the first quarter of 2021. *See 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 realized commodity prices and higher sales volumes.

Equity in earnings of affiliates increased $400 million in 2021, primarily due to higher earnings driven by higher LNG and crude prices, partially offset by a higher effective tax rate related to equity method investments 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 million gain related to our 2020 Australia-West divestiture and a $179 million loss associated with the sale of noncore assets in our Other International segment. The decreases were partially offset by $200 million related to a FID bonus associated with our Australia-West divestiture, gains recognized for contingent payments associated with previous dispositions in our Canada and Lower 48 segments and gains on sales of certain noncore assets in our Lower 48 segment.

Other income (loss) increased $1.7 billion in 2021, primarily due to a gain of $1,040 million on our CVE 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 and crude prices and volumes.

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

Selling, general and administrative expenses increased $289 million in 2021, primarily due to transaction and restructuring expenses associated with our Concho acquisition and higher compensation and benefits 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 2020 expenses including an $828 million impairment for the entire carrying value of capitalized undeveloped leasehold costs related to our Alaska North Slope Gas asset, the early cancellation of our 2020 winter exploration program in Alaska, and absence of unproved property impairment and dry hole expenses from 2020 for the Kamunsu East Field in Malaysia. 2021 also saw lower dry hole expenses in Alaska.

Impairments decreased $139 million in 2021, primarily due to the absence of impairments recognized in 2020 for noncore assets in our Lower 48 segment partially offset by an impairment in our APLNG investment 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 commodity prices and higher Lower 48 sales volumes.

Foreign currency transaction (gains) losses decreased $50 million in 2021 due to the absence of derivative gains and other remeasurements.

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

Summary Operating Statistics

		2021	2020	2019
Average Net Production				
Crude oil (MBD)				
Consolidated Operations		**816**	555	692
Equity affiliates		**13**	13	13
Total crude oil		**829**	568	705
Natural gas liquids (MBD)				
Consolidated Operations		**134**	97	107
Equity affiliates		**8**	8	8
Total natural gas liquids		**142**	105	115
Bitumen (MBD)		**69**	55	60
Natural gas (MMCFD)				
Consolidated Operations		**2,109**	1,339	1,753
Equity affiliates		**1,053**	1,055	1,052
Total natural gas		**3,162**	2,394	2,805
Total Production (MBOED)		**1,567**	1,127	1,348
	Dollars Per Unit			
Average Sales Prices				
Crude oil (per bbl)				
Consolidated Operations	$	**67.61**	39.56	60.98
Equity affiliates		**69.45**	39.02	61.32
Total crude oil		**67.64**	39.54	60.99
Natural gas liquids (per bbl)				
Consolidated Operations		**31.04**	12.90	18.73
Equity affiliates		**54.16**	32.69	36.70
Total natural gas liquids		**32.45**	14.61	20.09
Bitumen (per bbl)		**37.52**	8.02	31.72
Natural gas (per mcf)				
Consolidated Operations		**6.00**	3.17	4.25
Equity affiliates		**5.31**	3.71	6.29
Total natural gas		**5.77**	3.41	5.03
	Millions of Dollars			
Worldwide Exploration Expenses				
General and administrative; geological and geophysical, lease rental, and other	$	**300**	374	322
Leasehold impairment		**10**	868	221
Dry holes		**34**	215	200
Total Exploration Expenses	$	**344**	1,457	743

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

Total production, including Libya, of 1,567 MBOED increased 440 MBOED or 39 percent in 2021 compared 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 export terminal 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 disposition.

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

Alaska

		2021	2020	2019
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**1,386**	(719)	1,520
Average Net Production				
Crude oil (MBD)		**178**	181	202
Natural gas liquids (MBD)		**16**	16	15
Natural gas (MMCFD)		**16**	10	7
Total Production (MBOED)		**197**	198	218
Average Sales Prices				
Crude oil ($ per bbl)	$	**69.87**	42.12	64.12
Natural gas ($ per mcf)		**2.81**	2.91	3.19

The Alaska segment primarily explores for, produces, transports and markets crude oil, NGLs and natural gas. In 2021, Alaska contributed 19 percent of our consolidated liquids production and less than 1 percent of our 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 in 2020. Earnings were positively impacted by:

- Higher realized crude oil prices.
- Absence of 2020 exploration expenses, including a $648 million after-tax impairment associated with the carrying value of our Alaska North Slope Gas assets and the early cancellation of our winter 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 prices.

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 interest changes associated with periodic redetermination.
- Improved performance in the Greater Prudhoe Area and Western North Slope assets.
- New wells online across the segment.

Lower 48

		2021	2020	2019
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**4,932**	(1,122)	436
Average Net Production				
Crude oil (MBD)		**447**	213	266
Natural gas liquids (MBD)*		**110**	74	81
Natural gas (MMCFD)*		**1,340**	585	622
Total Production (MBOED)		**780**	385	451
Average Sales Prices				
Crude oil ($ per bbl)**	$	**66.12**	35.17	55.30
Natural gas liquids ($ per bbl)		**30.63**	12.13	16.83
Natural gas ($ per mcf)**		**4.38**	1.65	2.12

**Includes conversion of previously acquired Concho two-stream contracts to three-stream initiated in the fourth quarter of 2021.*
***Average sales prices, including the impact of hedges settling per initial contract terms in the first quarter of 2021 assumed in our Concho acquisition were $65.19 per barrel for crude oil and $4.33 per mcf for natural gas for the year ended December 31, 2021. As of 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 of Mexico. During 2021, the Lower 48 contributed 55 percent of our consolidated liquids production and 64 percent of our 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 million in 2020. 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 curtailments.
- Lower impairments, primarily related to developed properties in our noncore assets which were 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 income taxes primarily due to higher production volumes. Partially offsetting the increase in DD&A expenses were lower rates from price-related reserve revisions.
- Impacts resulting from our Concho acquisition, including higher selling, general and administrative expenses for transaction and restructuring charges, as well as realized losses on derivative settlements. See *Note 3* and *Note 12*.

Production

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

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

These production increases were partly offset by:

- Normal field decline.

Canada

		2021*	2020*	2019**
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**458**	(326)	279
Average Net Production				
Crude oil (MBD)		**8**	6	1
Natural gas liquids (MBD)		**4**	2	-
Bitumen (MBD)		**69**	55	60
Natural gas (MMCFD)		**80**	40	9
Total Production (MBOED)		**94**	70	63
Average Sales Prices				
Crude oil ($ per bbl)	$	**56.38**	23.57	40.87
Natural gas liquids ($ per bbl)		**31.18**	5.41	19.87
Bitumen ($ per bbl)		**37.52**	8.02	31.72
Natural gas ($ per mcf)		**2.54**	1.21	0.49

**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 2021, Canada contributed 8 percent of our consolidated liquids 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 million in 2020. 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 2021 associated 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 Montney production.

Production
Total average production increased 24 MBOED in 2021 compared with 2020. The production increase was 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	2019
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**1,167**	448	3,170
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**118**	86	138
Natural gas liquids (MBD)		**4**	4	7
Natural gas (MMCFD)		**313**	275	478
Total Production (MBOED)		**175**	136	224
Average Sales Prices				
Crude oil ($ per bbl)	$	**68.97**	43.30	64.94
Natural gas liquids ($ per bbl)		**43.97**	23.27	29.37
Natural gas ($ per mcf)		**13.27**	3.23	4.92

The Europe, Middle East and North Africa segment consists of operations principally located in the Norwegian sector of the North Sea; the Norwegian Sea; Qatar; Libya; and terminalling operations in the U.K. In 2021, our Europe, Middle East and North Africa operations contributed 12 percent of our consolidated liquids 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 2021 compared 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 the increase in DD&A expenses were lower rates from positive reserve revisions.

Consolidated Production

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

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

These production increases were partly offset by:

- Normal field decline.

Asia Pacific

		2021	2020	2019
Net Income (Loss) Attributable to ConocoPhillips ($MM)	**$**	**453**	962	1,483
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**65**	69	85
Natural gas liquids (MBD)		**-**	1	4
Natural gas (MMCFD)		**360**	429	637
Total Production (MBOED)		**125**	141	196
Average Sales Prices				
Crude oil ($ per bbl)	**$**	**70.36**	42.84	65.02
Natural gas liquids ($ per bbl)		**-**	33.21	37.85
Natural gas ($ per mcf)		**6.56**	5.39	5.91

The Asia Pacific segment has operations in China, Indonesia, Malaysia and Australia. During 2021, Asia Pacific contributed 6 percent of our consolidated liquids production and 17 percent of our consolidated natural gas production.

Net Income Attributable to ConocoPhillips

Asia Pacific reported earnings of $453 million in 2021, compared with $962 million in 2020. The decrease 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 Australia-West 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 decrease was 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 Indonesia from coal supply restrictions.

Other International

		2021	2020	2019
Net Income (Loss) Attributable to ConocoPhillips ($MM)	$	**(107)**	(64)	263

The Other International segment includes exploration and appraisal activities in Colombia as well as contingencies associated with prior operations in other countries. As a result of our Concho acquisition, we refocused our 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 loss of $64 million in 2020. Earnings were negatively impacted by:

- A $137 million after-tax loss on divestiture related to our Argentina exploration interests. *See Note 3*.
- Absence of a $29 million after-tax benefit to earnings from the dismissal of arbitration related to 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 impairment of capitalized undeveloped leasehold costs in Colombia in the fourth quarter of 2020.

Corporate and Other

		Millions of Dollars		
		2021	2020	2019
Net Income (Loss) Attributable to ConocoPhillips				
Net interest	$	**(801)**	(662)	(604)
Corporate general and administrative expenses		**(317)**	(200)	(252)
Technology		**25**	(26)	123
Other		**883**	(992)	771
	$	**(210)**	(1,880)	38

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

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

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 as well as LNG. Earnings from Technology increased by $51 million in 2021 compared with 2020, 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, holding gains or losses on equity securities, and pension settlement expense. Earnings in “Other” increased by $1,875 million in 2021 compared with 2020, primarily due to a gain of $1,040 million on our CVE common shares in 2021, compared with a $855 million loss in 2020.

Capital Resources and Liquidity

Financial Indicators

	Millions of Dollars Except as Indicated		
	2021	2020	2019
Net cash provided by operating activities	$ **16,996**	4,802	11,104
Cash and cash equivalents	**5,028**	2,991	5,088
Short-term investments	**446**	3,609	3,028
Short-term debt	**1,200**	619	105
Total debt	**19,934**	15,369	14,895
Total equity	**45,406**	29,849	35,050
Percent of total debt to capital*	**31 %**	34	30
Percent of floating-rate debt to total debt	**4 %**	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 2021, the primary uses of our available cash were $8.7 billion for the acquisition of Shell Permian; $5.3 billion to support our ongoing capital expenditures and investments program; $3.6 billion to repurchase our common stock; $2.4 billion to pay dividends; and $1.2 billion for hedging, transaction and restructuring costs. In 2021, cash and cash equivalents increased by $2.0 billion to $5.0 billion.

At December 31, 2021, we had cash and cash equivalents of $5.0 billion, short-term investments of $0.4 billion, and available borrowing capacity under our credit facility of $6.0 billion, totaling approximately $11.5 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 meet 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

In 2021, cash provided by operating activities was $17 billion, compared with $4.8 billion for 2020. The increase is primarily due to higher realized commodity prices and higher sales volumes, mostly resulting from our acquisition of Concho. The increase was partly offset by the $0.8 billion in settlement of oil and gas hedging positions acquired from Concho, and approximately $0.4 billion of transaction and restructuring costs.

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

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Full-year production averaged 1,567 MBOED in 2021. Full-year production excluding Libya averaged 1,527 MBOED. Adjusting for closed acquisitions and dispositions, impacts from 2020 curtailments, 2021 Winter Storm Uri and the conversion of Concho two-stream contracted volumes to a three-stream basis, production increased 28 MBOED or 2 percent. First quarter 2022 production is expected to be 1.75 MMBOED to 1.79 MMBOED. 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. Reserve replacement represents the net change in proved reserves, net of production, divided by our current year production. For information on proved reserves, including both developed and undeveloped reserves, *see the reserve table disclosures contained in "Supplementary Data – Oil and Gas Operations." See "Item 1A—Risk Factors – Unless we successfully develop our resources, the scope of our business will decline, resulting in an adverse impact to our business."*

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

Investing Activities

In 2021, we invested $5.3 billion in capital expenditures. Capital expenditures invested in 2020 and 2019 were $4.7 billion and $6.6 billion, respectively. For information about our capital expenditures and investments, see the "Capital Expenditures and Investments" section.

In December 2021, we completed our acquisition of Shell's assets in the Delaware Basin for cash consideration of approximately $8.7 billion after customary adjustments. We funded this transaction with cash on hand. We completed our acquisition of Concho on January 15, 2021. The assets acquired in the transaction included $382 million of cash. The net impact of these items is recognized within "Acquisition of businesses, net of cash 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 year-end 2023. Only proceeds from transactions announced or initiated in the third quarter of 2021 or later will be counted toward this target. The proceeds from these transactions will be used in accordance with the company's priorities, including returns of capital to shareholders and reduction of gross debt. To date, we have achieved $0.3 billion from 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 mentioned above, we also received cash proceeds of $1.14 billion from sales of our investment in CVE common shares and $244 million of contingent payments related to dispositions completed before 2021. *See Note 3.* In May 2021, we announced and began a paced monetization of our investment in CVE with the plan to direct proceeds toward our existing share repurchase program. We expect to fully dispose of our CVE common shares by early 2022, however, the sales pace will be guided by market conditions, and we retain discretion to adjust accordingly. *See Note 5.*

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. We also received proceeds of $359 million and $184 million from 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. *See Note 3.*

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 in highly liquid instruments with maturities within the year. Funds we consider available to maintain resiliency in longer term price downturns and to capture opportunities outside a given operating plan may be invested in instruments with maturities greater than one year. *See Note 12*.

Financing Activities

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. 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 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 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 no commercial paper outstanding and no direct borrowings or letters of credit, we had access to $6.0 billion in available borrowing capacity under the revolving credit facility at December 31, 2021.

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 and in December 2020, we launched an offer to exchange Concho's publicly traded debt for debt issued by ConocoPhillips. There were no impacts to ConocoPhillips' credit ratings as a result of the debt exchange. In June 2021, we reaffirmed our commitment to preserving our 'A'-rated balance sheet by restating our intent to reduce gross debt by $5 billion over the next five years, driving a more resilient and efficient 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 '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-" with a "stable" outlook and affirmed this rating in November 2021. In October 2021, Moody's affirmed its "A3" rating of our long-term debt and revised its outlook from "stable" to "positive". In December 2021, Fitch affirmed 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 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 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, 2021 and 2020, we had direct bank letters of credit of $337 million and $249 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.

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

Capital Requirements

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

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

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

Consistent with our commitment to deliver value to shareholders, in 2021, we paid $2.4 billion, $1.75 per share of common stock, in ordinary dividends. This was an increase over 2020 and 2019, when we paid $1.69 and $1.34 per share of common stock, respectively. On February 3, 2022, we announced a quarterly dividend of $0.46 per share, payable March 1, 2022, to stockholders of record at the close of business on February 14, 2022. On January 14, 2022, we paid the first VROC payment of $0.20 per share to shareholders of record as of January 3, 2022. On February 3, 2022, we announced a VROC of $0.30 per share, payable on April 14, 2022, to stockholders of record at the close of business on March 31, 2022.

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

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

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

In addition to the priorities described above, we have contractual obligations to purchase goods and services of approximately $11.8 billion. We expect to fulfill $6 billion of these obligations in 2022. These figures exclude purchase commitments for jointly owned fields and facilities where we are not the operator. Purchase obligations of $5.3 billion 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 and store commodities. Purchase obligations of $5.3 billion 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		
	2021	2020	2019
Alaska	$ 982	1,038	1,513
Lower 48	3,129	1,881	3,394
Canada	203	651	368
Europe, Middle East and North Africa	534	600	708
Asia Pacific	390	384	584
Other International	33	121	8
Corporate and Other	53	40	61
Capital Program*	$ **5,324**	4,715	6,636

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

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

- Development activities in the Lower 48, primarily Permian, Eagle Ford, and Bakken.
- Appraisal and development activities in Alaska related to the Western North Slope and development activities in the Greater Kuparuk Area.
- Appraisal and development activities in the Montney and optimization of oil sands development in 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 plan includes funding for ongoing development drilling programs, major projects, exploration and appraisal activities, base maintenance and $0.2 billion for projects to reduce the company's scope 1 and 2 emissions intensity and investments in 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 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 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.

Upon completing the Concho acquisition on January 15, 2021, we assumed Concho's publicly traded debt of approximately $3.9 billion in aggregate principal amount, which was recorded at the fair value of $4.7 billion on the acquisition date. We completed a debt exchange offer that settled on February 8, 2021, of which 98 percent, or approximately $3.8 billion in aggregate principal amount of Concho's notes, were tendered and accepted for new debt issued by ConocoPhillips. The new debt issued in the exchange is fully and unconditionally guaranteed by ConocoPhillips Company. Both the guarantor and issuer of the exchange debt is reflected within the Obligor Group presented here. *See Note 3* and *Note 9.*

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

Summarized Income Statement Data	Millions of Dollars	
		2021
Revenues and Other Income	$	30,457
Income (loss) before income taxes*		8,017
Net income (loss)		8,079
Net Income (Loss) Attributable to ConocoPhillips		8,079

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

Summarized Balance Sheet Data

	Millions of Dollars	
		December 31, 2021
Current assets	$	7,689
Amounts due from Non-Obligated Subsidiaries, current		1,927
Noncurrent assets		69,841
Amounts due from Non-Obligated Subsidiaries, noncurrent		7,281
Current liabilities		8,005
Amounts due to Non-Obligated Subsidiaries, current		3,477
Noncurrent liabilities		30,677
Amounts due to Non-Obligated Subsidiaries, noncurrent		13,007

Contingencies

We are subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated. See "Critical Accounting Estimates" and *Note 11* for information on contingencies.

Legal and Tax Matters

We are subject to various lawsuits and claims, including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, climate change, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties, 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 adequacy of current accruals and determines if an adjustment of existing accruals, or establishment of new accruals, is required. *See Note 17*.

Environmental

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

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

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

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

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

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

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

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that 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, 2021, there were 15 sites around the U.S. in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

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

Expensed environmental costs were $632 million in 2021 and are expected to be about $642 million and $700 million in 2022 and 2023, respectively. Capitalized environmental costs were $184 million in 2021 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 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, 2021, our balance sheet included total accrued environmental costs of $187 million, compared with $180 million at December 31, 2020, 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.

See Item 1A—Risk Factors – 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 and Note 11 for information on environmental litigation.

Climate Change
Continuing political and social attention to the issue of global climate change has resulted in a broad range of proposed or promulgated state, national and international laws focusing on GHG reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation 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 2021 was approximately $19 million (net share before-tax).
- U.K. Emissions Trading Scheme, the program with which the U.K. has replaced the ETS. Our cost of compliance with the U.K. ETS in 2021 was approximately $2.8 million (net share before-tax).
- The Alberta Technology Innovation and Emissions Reduction (TIER) regulation requires any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or equivalent, per year to meet a facility benchmark intensity. The total cost of these regulations in 2021 was approximately $1 million (net share before-tax).
- 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 U.S. government has announced on September 17, 2021 the Global Methane Pledge, a global initiative to reduce global methane emissions by at least 30 percent from 2020 levels by 2030.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon legislation in 2021 were fees of approximately $35 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 $5.7 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 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. Accordingly, the U.S. administration set a new target on April 22, 2021 of a 50 to 52 percent reduction in GHG emissions from 2005 levels in 2030.

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

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

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

See Item 1A—Risk Factors – Existing and future laws, regulations and internal initiatives relating to global climate changes, 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 and Note 11 for information on climate change litigation.

Company Response to Climate-Related Risks

The company has responded by putting in place a Sustainable Development Risk Management Standard covering the assessment and registration 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 and net equity 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 control or in which we have ownership interest.
- Scope 2 emissions are indirect GHG emissions from the generation of purchased electricity or steam that we 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 the company-wide targets. In September 2021, we increased our interim operational target and have set it to reduce our gross operated and net equity (scope 1 and 2) emissions intensity by 40 to 50 percent from 2016 levels by 2030, an improvement from the previously announced target of 35 to 45 percent on only a gross operated basis, with an ambition to achieve net-zero operated emissions by 2050. We have joined the World Bank Flaring Initiative to work towards zero routine flaring of associated gas by 2030, with an ambition to meet that goal by 2025.
- 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. The company does not use an estimated market cost of GHG emissions when assessing reserves in jurisdictions without existing GHG regulations. This is in contrast to changes to the cost of existing GHG emission regulations which can impact our reserves calculations.
- External engagement: Our external engagement aims to differentiate ConocoPhillips within the oil and 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* 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 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 activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of G&G seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been recognized.

<u>Property Acquisition Costs</u>

At year-end 2021, we held $9.3 billion of net capitalized unproved property costs which consisted primarily of individually significant and pooled leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, and to a lesser extent, suspended exploratory wells and capitalized interest. This amount increased by $6.9 billion at December 31, 2021 as compared to December 31, 2020, primarily due to the Concho and Shell Permian acquisitions in the Permian Basin where we have an ongoing significant and active development program. Outside of the Permian Basin, the remaining $2.0 billion is concentrated in 9 major development areas. Management periodically assesses our unproved property for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For insignificant 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, including estimates of future expirations, and pools that leasehold information with others in similar geographic areas. 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.

<u>Exploratory Costs</u>

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.

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

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. See Oil and Gas supplemental disclosures for additional information.

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 reach the end of its economic 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; 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 reserves is also important to the income statement because the proved 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 2021, the net book value of productive PP&E subject to a unit-of-production calculation was approximately $52 billion and the DD&A recorded on these assets in 2021 was approximately $7.0 billion. The estimated proved reserves for our consolidated operations were 2.5 billion BOE at the end of 2020 and 4.0 billion BOE at the end of 2021. 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 2021 would have increased by an estimated $774 million.

Business Combination—Valuation of Oil and Gas Properties

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

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

The assumptions and inputs incorporated within the fair value estimates are subject to considerable management judgement and are based on industry, market, and economic conditions prevalent at the time of the acquisition. Although we based these estimates on assumptions believed to be reasonable, these estimates are 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 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 for prices, volumes and future development plans. If 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 periods in which the 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 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 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 and related fair value calculations are based on estimated future production volumes, commodity prices, operating costs and capital decisions, considering all available evidence at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. *See Note 6 and Note 7*.

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 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 such a condition is judgmentally determined to be 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 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. Differing assumptions could affect the timing and the amount of an impairment of 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 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. 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. 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. 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 other 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 decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

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

Projected Benefit Obligations

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. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 100 basis-point decrease in the discount rate assumption would increase projected benefit obligations by $1.0 billion. 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 $70 million, while a 100 basis-point decrease in the return on plan assets assumption would increase annual benefit expense by $60 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or the elimination of the accrual of defined benefits for some or all of their future services for a significant number of employees, we could recognize a curtailment gain or loss. *See Note 16*.

Contingencies

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

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 by a valuation allowance if we deem it is more likely than not that some portion, or all, of the deferred tax assets will not be realized. In assessing the need for 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 inherent 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 prevailing oil and gas prices). *See Note 17*.

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 in applicable tax laws, including tax case rulings and legislative guidance, or expiration of the applicable statute of limitations. *See Note 17* regarding discussion of critical accounting estimates on deferred tax valuation allowances.

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, objectives of management for future operations and the anticipated impact of the Shell Enterprise LLC (Shell) transaction on the company's business and future financial and operating results 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 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 and uncertainties, including, but not limited to, the following:

- The impact of public health crises, including pandemics (such as COVID-19) and epidemics and any 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 or 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 decline in these prices relative to historical or future expected levels.
- The impact of significant declines in prices for crude oil, bitumen, natural gas, LNG and NGLs, which may result in recognition of impairment charges on our long-lived assets, leaseholds and nonconsolidated equity investments.
- The potential for insufficient liquidity or other factors, such as those described herein, that could impact our ability to repurchase shares and declare and pay dividends, whether fixed or variable.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Reductions in reserves replacement rates, whether as a result of the significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating E&P facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and NGLs.
- Inability to timely obtain or maintain permits, including those necessary for construction, drilling and/or development, or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.

- Failure to complete definitive agreements and feasibility studies for, and to complete construction of, announced and future 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, supply chain disruptions, 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, including 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 regulatory measures to limit or reduce GHG emissions.
- Liability resulting from litigation, including litigation directly or indirectly related to the transaction with Concho Resources Inc., or our failure to comply with applicable laws and regulations.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and NGLs pricing; regulation or taxation; 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 elect 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 terms 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 acquisitions, 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 elect to undertake in the future in the manner and timeframe we currently anticipate, if 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 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, such as potential 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 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, 2021, 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, 2021 and 2020, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk

The following table provides information about our debt instruments that are sensitive to changes in U.S. interest rates. The table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. A hypothetical 10 percent change in prevailing interest rates would not have a material impact on interest expense associated with our floating-rate 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 cash flows associated with fixed rate debt, unless we elect to repurchase or retire such debt prior to maturity.

Expected Maturity Date	Millions of Dollars Except as Indicated Debt Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2021				
2022	**$ 346**	**2.53 %**	**$ 500**	**1.03 %**
2023	**116**	**6.64**	**-**	**-**
2024	**459**	**3.51**	**-**	**-**
2025	**369**	**5.32**	**-**	**-**
2026	**1,355**	**5.06**	**-**	**-**
Remaining years	**14,338**	**5.80**	**283**	**0.11**
Total	**$ 16,983**		**$ 783**	
Fair value	**$ 21,668**		**$ 783**	
Year-End 2020				
2021	$ 133	8.47 %	$ 300	0.22 %
2022	346	2.53	500	1.12
2023	110	7.03	-	-
2024	459	3.51	-	-
2025	368	5.33	-	-
Remaining years	11,793	6.28	283	0.11
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 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, 2021 and 2020, 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 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, 2021, we had outstanding foreign currency exchange forward contracts to buy $1.9 billion AUD at $0.715 AUD against the U.S. dollar. 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. Based on the assumed volatility in the fair value calculation, the net fair value of these foreign currency contracts at December 31, 2021 and December 31, 2020, were a before-tax gain of $21 million and before-tax loss of $16 million, respectively. Based on an adverse hypothetical 10 percent change in the December 2021 and December 2020 exchange rate, this would result in an additional before-tax loss of $134 million and $39 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, 2021 and 2020, were as follows:

Foreign Currency Exchange Derivatives		In Millions			
		Notional		Fair Value*	
		2021	2020	**2021**	2020
Sell Canadian dollar, buy U.S. dollar	CAD	**-**	450	**-**	(16)
Buy Canadian dollar, sell U.S. dollar	CAD	**77**	80	**(1)**	2
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 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, 2021. 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, 2021. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the assets acquired from Shell Enterprise LLC in December 2021. The total assets acquired represented approximately 10 percent of the company's consolidated total assets at December 31, 2021.

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

/s/ Ryan M. Lance

Ryan M. Lance
Chairman and
Chief Executive Officer

/s/ William L. Bullock, Jr.

William L. Bullock, Jr.
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, 2021 and 2020, 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, 2021, 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 as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, 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 17, 2022, expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for asset retirement obligations for certain offshore properties

Description of the Matter

At December 31, 2021, the asset retirement obligation (ARO) balance totaled $5.9 billion. As further described in Note 8, 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 and higher estimation uncertainty related to plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms, facilities and pipelines costs (collectively, removal costs). Furthermore, given certain of these assets are nearing the end of their operations, the impact of changes in these AROs may result in a material impact to earnings given the relatively short remaining useful lives of the assets.

Auditing the Company's AROs for the obligations identified above is complex and highly judgmental due to the significant estimation required by management in determining the obligations. In particular, the estimates were sensitive to significant subjective assumptions such as removal cost estimates and end of field life, which are affected by expectations about future market or economic conditions.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligations. We also tested management's controls over the completeness and accuracy of the financial data used in the valuation.

To test the AROs for the obligations identified above, our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, including removal cost estimates and end of field life assumptions. For example, we evaluated removal cost estimates by comparing to settlements and recent removal activities and costs. We also compared end of field life assumptions to production forecasts.

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

Description of the Matter

At December 31, 2021, the net book value of the Company's proved oil and gas properties, plants and equipment (PP&E) was $52 billion, and depreciation, depletion and amortization (DD&A) expense was $7.0 billion for the year then ended. As described in Note 1, under the successful efforts method of accounting, DD&A of PP&E on producing hydrocarbon properties and steam-assisted gravity drainage facilities and certain 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.

Proved oil and gas reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating proved oil and gas reserves. Estimating proved oil and gas 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 proved oil and gas reserves, management also used an independent petroleum engineering consulting firm to perform a review of the processes and controls used by the Company's internal reservoir engineers to determine estimates of proved oil and gas reserves.

Auditing the Company's DD&A calculation is complex because of the use of the work of the internal reservoir engineers and 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 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 processes to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the internal reservoir engineers for use in estimating proved oil and gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers primarily responsible for overseeing the preparation of the proved oil and gas 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, we evaluated the completeness and accuracy of the financial data and inputs described above used by the internal reservoir engineers in estimating proved oil and gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the accuracy of the DD&A calculation, including comparing the proved oil and gas reserve amounts used in the calculation to the Company's reserve report.

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

Description of the Matter

During 2021, the Company closed its acquisition of Concho Resources Inc. and its acquisition of Permian assets from Shell Enterprises LLC resulting in the recognition of proved and unproved oil and gas properties within net properties, plants and equipment of $18.9 billion and $8.6 billion, respectively. As described in Note 3, the transactions were accounted for as business combinations under FASB ASC 805 using the acquisition method, which requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Oil and gas properties were valued using a discounted cash flow approach based on market participant assumptions and third party valuation experts were engaged by the Company to prepare fair value estimates. Significant inputs to the valuation of proved and unproved oil and gas properties include estimates of future commodity price assumptions and production profiles of reserve estimates, the pace of drilling plans, future operating costs and discount rates using a market-based weighted average cost of capital.

Auditing the Company's accounting for its valuation of proved and unproved oil and gas properties is complex and considerably judgmental due to the significant estimation required by management of reserves and resources associated with the acquired assets and the sensitivity of significant assumptions used in determining the fair value. In evaluating the reasonableness of management's estimates and assumptions used, the audit testing procedures performed required a high degree of auditor judgment and additional effort, including involving internal specialists.

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 estimate the fair value of the acquired proved and unproved oil and gas properties, including management's review of the significant assumptions used as inputs to the fair value calculations and final recording of the analysis.

To test the estimated fair value of the acquired proved and unproved oil and gas properties, our audit procedures included, among others, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data supporting the significant assumptions. For example, we compared certain significant assumptions to current industry, third-party data and historical results for reasonableness. We also performed sensitivity analyses of significant assumptions, to evaluate the extent of their impact to the fair value calculation. In addition, we involved our valuation specialists to assist with certain significant assumptions included in the fair value estimate. Furthermore, we evaluated the professional qualifications and objectivity of the third party valuation specialist engaged by the Company to prepare the fair value of the acquired proved and unproved oil and gas properties.

/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 31, 2021, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, ConocoPhillips (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on the COSO criteria. As indicated under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying Reports of Management, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the assets acquired from Shell Enterprise LLC, which is included in the 2021 consolidated financial statements of ConocoPhillips and constituted approximately 10 percent of consolidated total assets as of December 31, 2021. Our audit of internal control over financial reporting of ConocoPhillips also did not include an evaluation of 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 Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2021 and 2020, 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, 2021, and the related notes and 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 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 audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2022

Consolidated Income Statement **ConocoPhillips**

Years Ended December 31		Millions of Dollars		
		2021	2020	2019
Revenues and Other Income				
Sales and other operating revenues	$	**45,828**	18,784	32,567
Equity in earnings of affiliates		**832**	432	779
Gain on dispositions		**486**	549	1,966
Other income (loss)		**1,203**	(509)	1,358
Total Revenues and Other Income		**48,349**	19,256	36,670
Costs and Expenses				
Purchased commodities		**18,158**	8,078	11,842
Production and operating expenses		**5,694**	4,344	5,322
Selling, general and administrative expenses		**719**	430	556
Exploration expenses		**344**	1,457	743
Depreciation, depletion and amortization		**7,208**	5,521	6,090
Impairments		**674**	813	405
Taxes other than income taxes		**1,634**	754	953
Accretion on discounted liabilities		**242**	252	326
Interest and debt expense		**884**	806	778
Foreign currency transaction (gains) losses		**(22)**	(72)	66
Other expenses		**102**	13	65
Total Costs and Expenses		**35,637**	22,396	27,146
Income (loss) before income taxes		**12,712**	(3,140)	9,524
Income tax provision (benefit)		**4,633**	(485)	2,267
Net income (loss)		**8,079**	(2,655)	7,257
Less: net income attributable to noncontrolling interests		**-**	(46)	(68)
Net Income (Loss) Attributable to ConocoPhillips	$	**8,079**	(2,701)	7,189
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic	$	**6.09**	(2.51)	6.43
Diluted		**6.07**	(2.51)	6.40
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,324,194**	1,078,030	1,117,260
Diluted		**1,328,151**	1,078,030	1,123,536

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income ConocoPhillips

Years Ended December 31	Millions of Dollars		
	2021	2020	2019
Net Income (Loss)	**$ 8,079**	(2,655)	7,257
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)	(35)
Net change	**(38)**	(3)	(35)
Net actuarial gain (loss) arising during the period	**357**	(210)	(55)
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)	**178**	117	146
Net change	**535**	(93)	91
Nonsponsored plans*	**5**	1	(3)
Income taxes on defined benefit plans	**(108)**	20	(2)
Defined benefit plans, net of tax	**394**	(75)	51
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	699
Income taxes on foreign currency translation adjustments	**-**	3	(4)
Foreign currency translation adjustments, net of tax	**(124)**	212	695
Other Comprehensive Income, Net of Tax	**268**	139	746
Comprehensive Income (Loss)	**8,347**	(2,516)	8,003
Less: comprehensive income attributable to noncontrolling interests	**-**	(46)	(68)
Comprehensive Income (Loss) Attributable to ConocoPhillips	**$ 8,347**	(2,562)	7,935

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2021	2020
Assets			
Cash and cash equivalents	$	**5,028**	2,991
Short-term investments		**446**	3,609
Accounts and notes receivable (net of allowance of $2 and $4, respectively)		**6,543**	2,634
Accounts and notes receivable—related parties		**127**	120
Investment in Cenovus Energy		**1,117**	1,256
Inventories		**1,208**	1,002
Prepaid expenses and other current assets		**1,581**	454
Total Current Assets		**16,050**	12,066
Investments and long-term receivables		**7,113**	8,017
Loans and advances—related parties		**-**	114
Net properties, plants and equipment (net of accumulated DD&A of $64,735 and $62,213, respectively)		**64,911**	39,893
Other assets		**2,587**	2,528
Total Assets	$	**90,661**	62,618
Liabilities			
Accounts payable	$	**5,002**	2,669
Accounts payable—related parties		**23**	29
Short-term debt		**1,200**	619
Accrued income and other taxes		**2,862**	320
Employee benefit obligations		**755**	608
Other accruals		**2,179**	1,121
Total Current Liabilities		**12,021**	5,366
Long-term debt		**18,734**	14,750
Asset retirement obligations and accrued environmental costs		**5,754**	5,430
Deferred income taxes		**6,179**	3,747
Employee benefit obligations		**1,153**	1,697
Other liabilities and deferred credits		**1,414**	1,779
Total Liabilities		**45,255**	32,769
Equity			
Common stock (2,500,000,000 shares authorized at $0.01 par value)			
Issued (2021—2,091,562,747 shares; 2020—1,798,844,267 shares)			
Par value		**21**	18
Capital in excess of par		**60,581**	47,133
Treasury stock (at cost: 2021—789,319,875 shares; 2020—730,802,089 shares)		**(50,920)**	(47,297)
Accumulated other comprehensive loss		**(4,950)**	(5,218)
Retained earnings		**40,674**	35,213
Total Equity		**45,406**	29,849
Total Liabilities and Equity	$	**90,661**	62,618

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2021	2020	2019
Cash Flows From Operating Activities			
Net income (loss)	$ **8,079**	(2,655)	7,257
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**7,208**	5,521	6,090
Impairments	**674**	813	405
Dry hole costs and leasehold impairments	**44**	1,083	421
Accretion on discounted liabilities	**242**	252	326
Deferred taxes	**1,346**	(834)	(444)
Undistributed equity earnings	**446**	645	594
Gain on dispositions	**(486)**	(549)	(1,966)
(Gain) loss on CVE common shares	**(1,040)**	855	(649)
Other	**(788)**	43	(351)
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**(2,500)**	521	505
Increase in inventories	**(160)**	(25)	(67)
Decrease (increase) in prepaid expenses and other current assets	**(649)**	76	37
Increase (decrease) in accounts payable	**1,399**	(249)	(378)
Increase (decrease) in taxes and other accruals	**3,181**	(695)	(676)
Net Cash Provided by Operating Activities	**16,996**	4,802	11,104
Cash Flows From Investing Activities			
Capital expenditures and investments	**(5,324)**	(4,715)	(6,636)
Working capital changes associated with investing activities	**134**	(155)	(103)
Acquisition of businesses, net of cash acquired	**(8,290)**	-	-
Proceeds from asset dispositions	**1,653**	1,317	3,012
Net sales (purchases) of investments	**3,091**	(658)	(2,910)
Collection of advances/loans—related parties	**105**	116	127
Other	**87**	(26)	(108)
Net Cash Used in Investing Activities	**(8,544)**	(4,121)	(6,618)
Cash Flows From Financing Activities			
Issuance of debt	**-**	300	-
Repayment of debt	**(505)**	(254)	(80)
Issuance of company common stock	**145**	(5)	(30)
Repurchase of company common stock	**(3,623)**	(892)	(3,500)
Dividends paid	**(2,359)**	(1,831)	(1,500)
Other	**7**	(26)	(119)
Net Cash Used in Financing Activities	**(6,335)**	(2,708)	(5,229)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	**(34)**	(20)	(46)
Net Change in Cash, Cash Equivalents and Restricted Cash	**2,083**	(2,047)	(789)
Cash, cash equivalents and restricted cash at beginning of period	**3,315**	5,362	6,151
Cash, Cash Equivalents and Restricted Cash at End of Period	$ **5,398**	3,315	5,362

Restricted cash of $152 million and $218 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, 2021.
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.
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
Balances at December 31, 2018	$	18	46,879	(42,905)	(6,063)	34,010	125	32,064
Net income						7,189	68	7,257
Other comprehensive loss					746			746
Dividends declared—ordinary ($1.34 per share of common stock)						(1,500)		(1,500)
Repurchase of company common stock				(3,500)				(3,500)
Distributions to noncontrolling interests and other							(128)	(128)
Distributed under benefit plans			104					104
Changes in Accounting Principles*					(40)	40		-
Other						3	4	7
Balances at December 31, 2019	$	18	46,983	(46,405)	(5,357)	39,742	69	35,050
Net income (loss)						(2,701)	46	(2,655)
Other comprehensive income					139			139
Dividends declared—ordinary ($1.69 per share of common stock)						(1,831)		(1,831)
Repurchase of company common stock				(892)				(892)
Distributions to noncontrolling interests and other							(32)	(32)
Disposition							(84)	(84)
Distributed under benefit plans			150					150
Other						3	1	4
Balances at December 31, 2020	$	18	47,133	(47,297)	(5,218)	35,213	-	29,849
Net income						**8,079**	**-**	**8,079**
Other comprehensive income					**268**			**268**
Dividends declared								
Ordinary ($1.75 per share of common stock)						**(2,359)**		**(2,359)**
Variable return of cash ($0.20 per share of common stock)						**(260)**		**(260)**
Acquisition of Concho		**3**	**13,122**					**13,125**
Repurchase of company common stock				**(3,623)**				**(3,623)**
Distributed under benefit plans			**326**					**326**
Other						**1**	**-**	**1**
Balances at December 31, 2021	**$**	**21**	**60,581**	**(50,920)**	**(4,950)**	**40,674**	**-**	**45,406**

**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.

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 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 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.

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

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

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

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. *See Note 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).

- **Impairment of Properties, Plants and Equipment**—Long-lived assets 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 for prices, volumes and future development plans. If 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 is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for E&P assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates 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 and related fair value calculations are based on estimated future production volumes, commodity prices, operating costs and capital decisions, 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.

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 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 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—Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2021	2020
Crude oil and natural gas	$	**647**	461
Materials and supplies		**561**	541
Total inventories	$	**1,208**	1,002
Inventories valued on the LIFO basis	$	**395**	282

The estimated excess of current replacement cost over LIFO cost of inventories was approximately $251 million 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 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.

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 under 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)*		194,243
Number of shares of Concho stock awards outstanding (in thousands)*		1,599
Number of shares exchanged		195,842
Exchange ratio		1.46
Additional shares of ConocoPhillips common stock issued as consideration (in thousands)		285,929
Average price per share of ConocoPhillips common stock**	$	45.9025
Total Consideration (Millions)	**$**	**13,125**

**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 market participant and 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	$	382
Accounts receivable, net		745
Inventories		45
Prepaid expenses and other current assets		37
Investments and long-term receivables		333
Net properties, plants and equipment		18,923
Other assets		62
Total assets acquired	**$**	**20,527**
Liabilities Assumed		
Accounts payable	$	638
Accrued income and other taxes		56
Employee benefit obligations		4
Other accruals		510
Long-term debt		4,696
Asset retirement obligations and accrued environmental costs		310
Deferred income taxes		1,071
Other liabilities and deferred credits		117
Total liabilities assumed	**$**	**7,402**
Net assets acquired	**$**	**13,125**

With the completion of the Concho transaction, we acquired proved and unproved properties of approximately $11.8 billion and $6.9 billion, respectively.

We recognized approximately $157 million of transaction-related costs, all of which were expensed in the first 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	128
Selling, general and administration expenses	135	67	202
Exploration expenses	18	8	26
Taxes other than income taxes	4	2	6
Other expenses	-	29	29
	$ 157	**234**	**391**

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 $6,571 million and $2,330 million, respectively. The results associated with the Concho business for the 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 our 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 acquired include 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 market participant and internally generated price assumptions, production profiles, and operating and development cost assumptions. 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 $8.7 billion was allocated to the identifiable assets and liabilities based on their fair values at the acquisition date.

Assets Acquired		Millions of Dollars
Accounts receivable, net	$	337
Inventories		20
Net properties, plants and equipment		8,624
Other assets		50
Total assets acquired	**$**	**9,031**

Liabilities Assumed		
Accounts payable	$	211
Accrued income and other taxes		6
Other accruals		20
Asset retirement obligations and accrued environmental costs		86
Other liabilities and deferred credits		36
Total liabilities assumed	**$**	**359**
Net assets acquired	**$**	**8,672**

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 $44 million of transaction-related costs which were expensed during 2021.

Supplemental Pro Forma (unaudited)
The following tables summarize the unaudited supplemental pro forma financial information for the year 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 Combined
Total Revenues and Other Income	$	48,349	3,220	51,569
Income (loss) before income taxes		12,712	1,201	13,913
Net Income (Loss) attributable to ConocoPhillips		8,079	920	8,999
Earnings per share:				
Basic net loss	$	6.09		6.78
Diluted net loss		6.07		6.76

		Millions of Dollars			
		Year Ended December 31, 2020			
		As reported	Pro forma Concho	Pro forma Shell	Pro forma Combined
Total Revenues and Other Income	$	19,256	3,762	1,685	24,703
Income (loss) before income taxes		(3,140)	787	(247)	(2,600)
Net Income (Loss) attributable to ConocoPhillips		(2,701)	498	(189)	(2,392)
Earnings per share:					
Basic net loss	$	(2.51)			(1.75)
Diluted net loss		(2.51)			(1.75)

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 transactions 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 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 results to reverse 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-production 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 exercising our preemption right to purchase an additional 10 percent shareholding interest in APLNG from Origin Energy for $1.645 billion, which will be funded from cash on the balance sheet, before customary adjustments. The effective date of the transaction will be July 1, 2020 with closing anticipated to occur in the first quarter of 2022 subject to Australian government approval. 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 quarter 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 date. Results of operations related to this transaction are reflected in our Asia Pacific segment. *See Note 11*.

In the second half of 2021, we sold our interests in certain noncore assets in our Lower 48 segment for approximately $250 million after customary adjustments, recognizing a before-tax gain on sale of approximately $58 million. We also completed the sale of our noncore exploration interests in Argentina, recognizing a before-tax loss on disposition of $179 million. Results of operations for Argentina were reported in our Other International segment.

In 2021, we recorded contingent payments of $369 million relating to previous dispositions. The contingent payments are recorded as gain on disposition on our consolidated income statement and are reflected within our Canada and Lower 48 segments. In our Canada segment, 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. The term for contingent payments in our Canada segment ends on May 16, 2022. In our Lower 48 segment, the contingent payment, paid on an annual basis, is calculated monthly at $7 million per month in which the U.S. Henry Hub price is at or above $3.20 per MMBTU. The term for contingent payments in our Lower 48 segment goes through 2023. No contingent payments were recorded in 2020.

Planned Dispositions

In December 2021, we entered into an agreement to sell two subsidiaries holding our Indonesia assets and operations to MedcoEnergi for $1.355 billion, before customary adjustments, with an effective date of January 1, 2021. The subsidiaries hold our 54 percent interest in the Indonesia Corridor Block Production Sharing Contract (PSC) and a 35 percent shareholding interest in the Transasia Pipeline Company. The net carrying value is approximately $0.4 billion, which consists primarily of PP&E. The assets met the held for sale criteria in the fourth quarter, and as of December 31, 2021, we have reclassified $0.3 billion of PP&E to "Prepaid expenses and other current assets" and $0.1 billion of noncurrent ARO to "Other accruals" on our consolidated balance sheet. The before-tax earnings associated with our Indonesia subsidiaries were $604 million, $394 million and $512 million for the years ended December 31, 2021, 2020 and 2019, respectively. This transaction is expected to close in early 2022, subject to regulatory approvals and other specific conditions precedent. Results of operations for the subsidiaries to be sold are reported within our Asia Pacific segment.

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 from 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 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 an 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 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 customary 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 we 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. 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. 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 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 and $372 million for the years ended 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 FID of 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 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.

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, including the gain on dispositions 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 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 $16 million and recognized a before-tax gain of $82 million. At the time of sale, the net carrying value consisted of $4 million of PP&E offset by $70 million of ARO. The Magnolia results of operations 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 Dollars	
	2021	2020
Equity investments	$ **6,701**	7,596
Loans and advances—related parties	**-**	114
Long-term receivables	**98**	137
Long-term investments in debt securities	**248**	217
Other investments	**66**	67
	$ **7,113**	8,131

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 as process and export LNG.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of QatarEnergy (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		
	2021	2020	2019
Revenues	$ **11,824**	7,931	11,310
Income before income taxes	**3,946**	1,843	3,726
Net income	**2,557**	1,426	3,085

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

	Millions of Dollars	
	2021	2020
Current assets	$ **4,493**	2,579
Noncurrent assets	**36,602**	35,257
Current liabilities	**3,498**	2,110
Noncurrent liabilities	**17,465**	18,099

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 financing 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 Placement 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 2021 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 fair value which was below the carrying value of our existing investment in APLNG. Based on a review of the facts 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 impairment 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 as of 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 value 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. We 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 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. *See Note 3*.

Loans

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 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 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.

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	2020
Number of shares of CVE common stock (millions)	**91**	208
Ownership of issued and outstanding common stock	**4.5 %**	16.9
Closing price on NYSE on last trading day ($/share)	**$ 12.28**	6.04
Fair Value (millions of dollars)	**$ 1,117**	1,256

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 of 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	2019
Total Net gain (loss) on equity securities	**$ 1,040**	(855)	649
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)	649

Note 6—Suspended Wells and Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2021, 2020 and 2019:

	Millions of Dollars		
	2021	2020	2019
Beginning balance at January 1	**$ 682**	1,020	856
Additions pending the determination of proved reserves	**10**	164	239
Reclassifications to proved properties	**-**	(42)	(11)
Sales of suspended wells	**-**	(313)	(54)
Charged to dry hole expense	**(32)**	(147)	(10)
Ending balance at December 31	**$ 660**	682	1,020 *

**Includes $313 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	2019
Exploratory well costs capitalized for a period of one year or less	**$ 4**	156	206
Exploratory well costs capitalized for a period greater than one year	**656**	526	814
Ending balance	**$ 660**	682	1,020 *

**Includes $313 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	23

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	2004-2014
Willow—Alaska[1]	313	262	51	-
Surmont—Canada[1]	121	2	19	100
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	-	-	13
Other of $10 million or less each[1][2]	61	21	11	29
Total	$ 656	433	81	142

(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 asset. 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. As we had 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 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 carrying value of capitalized undeveloped leasehold costs and dry hole expenses of $111 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	2019
Alaska	$ **5**	-	-
Lower 48	**(8)**	804	402
Canada	**6**	3	2
Europe, Middle East and North Africa	**(24)**	6	1
Asia Pacific	**695**	-	-
	$ **674**	813	405

2021

We recorded an impairment of $688 million on our APLNG investment included within the Asia Pacific 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 in development plans. *See Note 13*.

In our Europe, Middle East and North Africa segment, we recorded a credit to impairment of $24 million due to 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 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 13*.

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 3*.

Note 8—Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2021	2020
Asset retirement obligations	$ **5,926**	5,573
Accrued environmental costs	**187**	180
Total asset retirement obligations and accrued environmental costs	**6,113**	5,753
Asset retirement obligations and accrued environmental costs due within one year*	**(359)**	(323)
Long-term asset retirement obligations and accrued environmental costs	$ **5,754**	5,430

**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. 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 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 2021 and 2020, our overall ARO changed as follows:

	Millions of Dollars	
	2021	2020
Balance at January 1	**$ 5,573**	6,206
Accretion of discount	**238**	248
New obligations	**555**	262
Changes in estimates of existing obligations	**(113)**	(307)
Spending on existing obligations	**(164)**	(116)
Property dispositions	**(108)**	(771)
Foreign currency translation	**(55)**	51
Balance at December 31	**$ 5,926**	5,573

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 at December 31, 2021 and 2020, respectively. In addition, both December 31, 2021 and 2020, included a $16 million accrual, 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 Dollars	
		2021	2020
9.125% Debentures due 2021	$	**-**	123
2.4% Notes due 2022		**329**	329
7.65% Debentures due 2023		**78**	78
3.35% Notes due 2024		**426**	426
8.2% Debentures due 2025		**134**	134
3.35% Notes due 2025		**199**	199
6.875% Debentures due 2026		**67**	67
4.95% Notes due 2026		**1,250**	1,250
7.8% Debentures due 2027		**203**	203
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**	92
7% Debentures due 2029		**200**	200
6.95% Notes due 2029		**1,549**	1,549
8.125% Notes due 2030		**390**	390
2.4% Notes due 2031		**489**	-
2.4% Notes due 2031		**11**	-
7.2% Notes due 2031		**575**	575
7.25% Notes due 2031		**500**	500
7.4% Notes due 2031		**500**	500
5.9% Notes due 2032		**505**	505
4.15% Notes due 2034		**246**	246
5.95% Notes due 2036		**500**	500
5.951% Notes due 2037		**645**	645
5.9% Notes due 2038		**600**	600
6.5% Notes due 2039		**2,750**	2,750
4.3% Notes due 2044		**750**	750
5.95% Notes due 2046		**500**	500
7.9% Debentures due 2047		**60**	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**	500
Marine Terminal Revenue Refunding Bonds due 2031 at 0.04% – 0.15% during 2021 and 0.1% – 7.5% during 2020		**265**	265
Industrial Development Bonds due 2035 at 0.04% – 0.12% during 2021 and 0.11% – 7.5% during 2020		**18**	18
Commercial Paper at 0.05% – 0.22% during 2021		**-**	300
Other		**35**	38
Debt at face value		**17,766**	14,292
Finance leases		**1,261**	891
Net unamortized premiums, discounts and debt issuance costs		**907**	186
Total debt		**19,934**	15,369
Short-term debt		**(1,200)**	(619)
Long-term debt	$	**18,734**	14,750

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, with an outstanding principal balance of $3.9 billion, which was recorded at fair value of $4.7 billion on the acquisition date. The adjustment to fair value of the senior notes of approximately $0.8 billion on the acquisition date will be amortized as an adjustment to interest expense over the remaining contractual terms of the senior notes.

In the first quarter of 2021, we completed a debt exchange offer related to the debt assumed from Concho. Of the approximately $3.9 billion in aggregate principal amount of Concho's senior notes offered in the exchange, 98 percent, or approximately $3.8 billion, was tendered and accepted. The new debt issued by ConocoPhillips had the same interest rates and maturity dates as the Concho senior notes. The portion not exchanged, approximately $67 million, remained outstanding across five series of senior notes issued by Concho. The debt exchange was treated as a debt modification for accounting purposes resulting in a portion of the unamortized fair value adjustment of the Concho senior notes allocated to the new debt issued by ConocoPhillips on the settlement date of the exchange. The new debt issued in the exchange is fully and unconditionally guaranteed by ConocoPhillips Company. *See Note 3.*

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 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 facility 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. With no commercial paper outstanding and no direct borrowings or letters of credit, we had access to $6.0 billion in available borrowing capacity under our revolving credit facility at December 31, 2021. We had no direct borrowings, letters of credit, and $300 million of commercial paper outstanding as of December 31, 2020.

For information on Finance Leases, *see Note 15*.

The current credit ratings on our long-term debt are:

- Fitch: "A" with a "stable" outlook.
- S&P: "A-" with a "stable" outlook.
- Moody's: "A3" with a "positive" 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, 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 the commercial paper market, we would still be able to access funds under our revolving credit facility.

At both December 31, 2021 and 2020, 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.

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-ventures 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.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $720 million, which consist primarily of guarantees of the residual value of leased office buildings, guarantees 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 five 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, 2021, the carrying value of these guarantees was approximately $8 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. The carrying amount recorded for these indemnifications at December 31, 2021, was approximately $20 million. Those related to environmental issues have terms that are generally indefinite and the maximum amounts of future payments are generally unlimited. 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. *See Note 11* for additional information about environmental liabilities.

Note 11—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 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 certain. *See Note 17*, 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 and record accruals for environmental liabilities based on management's best estimates. These estimates are based on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. EPA or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

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

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See *Note 8*, 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 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 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 such company with additional funds through advances and penalties for fees related to throughput 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 for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, ConocoPhillips was unable to reach agreement with respect to the empresa mixta structure mandated by the Venezuelan government's Nationalization Decree. As a result, Venezuela's national oil company, Petróleos de Venezuela, S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, ConocoPhillips initiated international arbitration on November 2, 2007, with the ICSID. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips' significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. In March 2019, the Tribunal unanimously ordered the government of Venezuela to pay ConocoPhillips approximately $8.7 billion in compensation for the government's unlawful expropriation of the company's investments in Venezuela in 2007. 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 annulment 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 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. 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 received approximately $768 million in connection with the ICC award. 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. 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.

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 government. ConocoPhillips and the ONRR entered into a settlement agreement on March 23, 2021, to resolve the dispute. All orders and associated appeals have been withdrawn with prejudice.

Beginning in 2017, governmental 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.

Several Louisiana parishes and the State of Louisiana have filed 43 lawsuits under Louisiana's State and Local 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 uncertainty about these claims (both as to scope and damages) and we continue to evaluate our exposure in these lawsuits.

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. BSEE's order to ConocoPhillips is premised on its connection to Phillips Petroleum Company, a legacy company of ConocoPhillips, which held a historical 25 percent interest in this lease and operated these facilities, but sold its interest approximately 30 years ago. ConocoPhillips continues to evaluate our exposure in these lawsuits.

On May 10, 2021, ConocoPhillips filed arbitration under the rules of the Singapore International Arbitration Centre (SIAC) against Santos KOTN Pty Ltd. and Santos Limited for their failure to timely pay the $200 million bonus due upon FID of the Barossa development project under the sale and purchase agreement. Santos KOTN Pty Ltd. and Santos Limited have filed a response and counterclaim, and the arbitration is underway.

In July 2021, a federal securities class action was filed against Concho, certain of Concho's officers, and ConocoPhillips as Concho's successor in the United States District Court for the Southern District of Texas. On October 21, 2021, the court issued an order appointing Utah Retirement Systems and the Construction Laborers Pension Trust for Southern California as lead plaintiffs (Lead Plaintiffs). On January 7, 2022, the Lead Plaintiffs filed their consolidated complaint alleging that Concho made materially false and misleading statements regarding its business and operations in violation of the federal securities laws and seeking unspecified damages, attorneys' fees, costs, equitable/injunctive relief, and such other relief that may be deemed appropriate. We believe the allegations in the action are without merit, and we intend to vigorously defend this litigation.

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 business. The aggregate amounts of estimated payments under these various agreements are: 2022—$7 million; 2023—$7 million; 2024—$7 million; 2025—$7 million; 2026—$7 million; and 2027 and after—$43 million. Total payments under the agreements were $27 million in 2021, $25 million in 2020 and $25 million in 2019.

Note 12—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, 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	2020
Assets		
Prepaid expenses and other current assets	$ **1,168**	229
Other assets	**75**	26
Liabilities		
Other accruals	**1,160**	202
Other liabilities and deferred credits	**63**	18

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	2019
Sales and other operating revenues	$ **(228)**	19	141
Other income (loss)	**25**	4	4
Purchased commodities	**75**	11	(118)

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 contracts through December 31, 2022. During 2021, we recognized a loss on settlement of the contracts for $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 within "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	2020
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**4**	(20)
Basis	**(22)**	(10)

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	2020
Assets		
Prepaid expenses and other current assets	$ **28**	2
Liabilities		
Other accruals	**9**	16

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	2019
Foreign currency transaction (gains) losses	$ **(5)**	(40)	16

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

		In Millions Notional Currency	
		2021	2020
Foreign Currency Exchange Derivatives			
Buy British pound, sell euro	GBP	**155**	-
Sell British pound, buy euro	GBP	**-**	5
Sell Canadian dollar, buy U.S. dollar	CAD	**-**	370
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 to buy $1.9 billion AUD at $0.715 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 sell $0.45 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 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 and Long-Term Receivables	
	2021	2020	**2021**	2020	**2021**	2020
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					**-**	1
U.S. Government Obligations						
1 to 90 days	**431**	23	**-**	-		
	$ **5,018**	2,978	**225**	3,320	**-**	1

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

	Millions of Dollars					
	Carrying Amount					
	Cash and Cash Equivalents		Short-Term Investments		Investments and Long-Term Receivables	
	2021	2020	**2021**	2020	**2021**	2020
Major Security Type						
Corporate Bonds	$ **3**	-	**128**	130	**173**	143
Commercial Paper	**7**	13	**82**	155		
U.S. Government Obligations	**-**	-	**-**	4	**2**	13
U.S. Government Agency Obligations			**2**	-	**8**	17
Foreign Government Obligations			**7**	-	**2**	2
Asset-backed Securities			**2**	-	**63**	41
	$ **10**	13	**221**	289	**248**	216

Cash and Cash Equivalents and Short-Term Investments have remaining maturities within one 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 debt securities classified as available for sale at December 31:

	Millions of Dollars			
	Amortized Cost Basis		Fair Value	
	2021	2020	**2021**	2020
Major Security Type				
Corporate Bonds	$ **305**	271	**304**	273
Commercial Paper	**88**	168	**89**	168
U.S. Government Obligations	**2**	17	**2**	17
U.S. Government Agency Obligations	**10**	17	**10**	17
Foreign Government Obligations	**9**	2	**9**	2
Asset-Backed Securities	**65**	41	**65**	41
	$ **479**	516	**479**	518

As of December 31, 2021 and 2020, total unrealized losses for debt securities classified as available for sale with net losses were negligible. Additionally, as of December 31, 2021 and 2020, 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 years ended December 31, 2021 and 2020, proceeds from sales and redemptions of investments in debt securities classified as available for sale were $594 million and $422 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 of cash equivalents, short-term investments, long-term investments in debt securities, OTC derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, government money market funds, 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 corporate 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 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 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 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, 2021 and December 31, 2020, was $281 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 have been required to post $252 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 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 fair value hierarchy.

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. 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 our 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 our investments in U.S. government obligations classified as available for sale debt securities, which are valued using exchange prices.
- Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 2 also includes our investments in debt securities classified as available for sale including investments in corporate bonds, commercial paper, 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 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, 2021				December 31, 2020			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Investment in Cenovus Energy	**$ 1,117**	**-**	**-**	**1,117**	1,256	-	-	1,256
Investments in debt securities	**2**	**477**	**-**	**479**	17	501	-	518
Commodity derivatives	**562**	**619**	**62**	**1,243**	142	101	12	255
Total assets	**$ 1,681**	**1,096**	**62**	**2,839**	1,415	602	12	2,029
Liabilities								
Commodity derivatives	**$ 593**	**543**	**87**	**1,223**	120	91	9	220
Total liabilities	**$ 593**	**543**	**87**	**1,223**	120	91	9	220

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, 2021							
Assets	**$ 1,243**	**85**	**1,158**	**650**	**508**	**-**	**508**
Liabilities	**1,223**	**82**	**1,141**	**650**	**491**	**36**	**455**
December 31, 2020							
Assets	$ 255	2	253	157	96	10	86
Liabilities	220	1	219	157	62	4	58

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 Loss
Year ended December 31, 2021					
Net PP&E (held for use)					
December 31, 2021	**$ 472**	**-**	**-**	**472**	**80**
Equity Method Investments					
December 31, 2021	**5,574**	-	**5,574**	-	**688**
Year ended December 31, 2020					
Net PP&E (held for use)					
March 31, 2020	$ 65	-	-	65	522
December 31, 2020	268	-	-	268	287

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 value. The fair values were estimated based on internal discounted cash flow models using the following estimated assumptions: estimated 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 expenditures, 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	Range (Arithmetic Average)
December 31, 2021				
Lower 48 Gulf Coast and Rockies noncore field	$ 472	Discounted cash flow	Commodity production (MBOED)	0.2 - 17 (5.4)
			Commodity price outlook* ($/BOE)	$41.45 - $93.68 ($64.39)
			Discount rate**	7.3% - 9.7% (8.7%)

*Commodity price outlook based on a combination of external pricing service companies' and our internal outlook for years 2024-2050; 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.

	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Inputs	Range (Arithmetic Average)
March 31, 2020				
Wind River Basin	$ 65	Discounted cash flow	Natural gas production (MMCFD)	8.4 - 55.2 (22.9)
			Natural gas price outlook* ($/MMBTU)	$2.67 - $9.17 ($5.68)
			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 2.2% 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	Range (Arithmetic Average)
December 31, 2020				
Central Basin Platform	$ 244	Discounted cash flow	Commodity production (MBOED)	0.5 - 12.7 (3.4)
			Commodity price outlook* ($/BOE)	$37.35 - $115.29 ($73.80)
			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.

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 2021 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 fair 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 reported on the balance sheet approximates fair value. For those investments classified as available for sale debt securities, the carrying amount reported on the balance sheet is fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances—related parties.
- Investment in Cenovus Energy: *See Note 5* for a discussion of the carrying value and fair value 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 and 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 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.
- 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**	2020
Financial assets				
Investment in CVE common shares	$ **1,117**	1,256	**1,117**	1,256
Commodity derivatives	**593**	88	**593**	88
Investments in debt securities	**479**	518	**479**	518
Loans and advances—related parties	**114**	220	**114**	220
Financial liabilities				
Total debt, excluding finance leases	**18,673**	14,478	**22,451**	19,106
Commodity derivatives	**537**	59	**537**	59

<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 collateral 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	2019
Issued			
Beginning of year	**1,798,844,267**	1,795,652,203	1,791,637,434
Acquisition of Concho	**285,928,872**	-	-
Distributed under benefit plans	**6,789,608**	3,192,064	4,014,769
End of year	**2,091,562,747**	1,798,844,267	1,795,652,203
Held in Treasury			
Beginning of year	**730,802,089**	710,783,814	653,288,213
Repurchase of common stock	**58,517,786**	20,018,275	57,495,601
End of year	**789,319,875**	730,802,089	710,783,814

Preferred Stock

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

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, 2021 and 2020, we had 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 CVE common shares, the proceeds of which have been applied to share repurchases. Share repurchases since inception of our current program 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 that vary based on the nature of usage of the leased asset. Additionally, the company has executed certain leases that provide it with the option to extend or renew the term of the lease, terminate the lease prior to the end of the lease term, or purchase the leased asset as of the end of the lease term. In other cases, the company has executed lease agreements that require it to guarantee the residual value of certain leased office buildings. For additional information about guarantees, *see Note 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 company's leased asset classes existing as of the effective date and subject to the transition provisions of ASC Topic 842 and will be applied to all new or modified leases executed on or after January 1, 2019. For contractual arrangements executed in subsequent periods involving a new leased asset class, the company will determine at contract inception whether it will apply the optional practical expedient to the new leased asset class.

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

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

The company has historically recorded certain finance leases executed by investee companies accounted for under the proportionate consolidation method of accounting on its consolidated balance sheet on a proportional basis consistent with its ownership interest in the investee company. In addition, the company has historically recorded finance lease assets and liabilities associated with certain oil and gas joint ventures on a proportional basis pursuant to accounting guidance applicable prior to January 1, 2019. 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	Finance Leases
Right-of-Use Assets					
Properties, plants and equipment					
Gross	$		**1,812**		1,375
Accumulated DD&A			**(857)**		(721)
Net PP&E*			**955**		654
Prepaid expenses and other current assets	$	**16**	**2**		
Other assets		**649**		783	
Lease Liabilities					
Short-term debt**	$		**280**		168
Other accruals		**188**		226	
Long-term debt***			**981**		723
Other liabilities and deferred credits		**479**		559	
Total lease liabilities	$	**667**	**1,261**	785	891

* Includes proportionately consolidated finance lease assets of $208 million at December 31, 2021 and $258 million at December 31, 2020.
** Includes proportionately consolidated finance lease liabilities of $154 million at December 31, 2021 and $97 million at December 31, 2020.
*** Includes proportionately consolidated finance lease liabilities of $462 million at December 31, 2021 and $522 million at December 31, 2020.

The following table summarizes our lease costs:

		Millions of Dollars		
		2021	2020	2019
Lease Cost*				
Operating lease cost	$	**278**	321	341
Finance lease cost				
Amortization of right-of-use assets		**148**	163	99
Interest on lease liabilities		**27**	34	37
Short-term lease cost**		**21**	42	77
Total lease cost***	$	**474**	560	554

* The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers.
** Short-term leases are not recorded on our consolidated balance sheet.
*** 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	2020
Lease Term and Discount Rate		
Weighted-average term (years)		
Operating leases	**5.97**	6.11
Finance leases	**7.49**	7.12
Weighted-average discount rate (percent)		
Operating leases	**2.66**	2.78
Finance leases	**3.24**	4.27

The following table summarizes other lease information:

		Millions of Dollars		
		2021	2020	2019
Other Information*				
Cash paid for amounts included in the measurement of lease liabilities				
Operating cash flows from operating leases	$	**204**	232	203
Operating cash flows from finance leases		**6**	11	27
Financing cash flows from finance leases		**73**	255	81
Right-of-use assets obtained in exchange for operating lease liabilities	$	**174**	250	499
Right-of-use assets obtained in exchange for finance lease liabilities		**447**	426	26

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

The following table summarizes future lease payments for operating and finance leases at December 31, 2021:

		Millions of Dollars	
		Operating Leases	Finance Leases
Maturity of Lease Liabilities			
2022	$	195	341
2023		143	199
2024		114	166
2025		68	143
2026		50	139
Remaining years		159	462
Total*		729	1,450
Less: portion representing imputed interest		(62)	(189)
Total lease liabilities	$	667	1,261

*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.

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 our postretirement health and life insurance plans follows:

	Millions of Dollars						
	Pension Benefits					Other Benefits	
	2021			2020		**2021**	2020
		U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation							
Benefit obligation at January 1	**$**	**2,548**	**4,403**	2,319	3,880	**170**	216
Service cost		**73**	**61**	85	54	**2**	2
Interest cost		**53**	**79**	66	85	**4**	6
Plan participant contributions		**-**	**-**	-	1	**16**	18
Plan amendments		**-**	**-**	-	2	**-**	(30)
Actuarial (gain) loss		**(117)**	**(176)**	319	398	**(16)**	7
Benefits paid		**(654)**	**(162)**	(241)	(151)	**(40)**	(49)
Curtailment		**12**	**-**	-	2	**1**	-
Recognition of termination benefits		**9**	**-**	-	3	**-**	-
Foreign currency exchange rate change		**-**	**(81)**	-	129	**-**	-
Benefit obligation at December 31*	**$**	**1,924**	**4,124**	2,548	4,403	**137**	170
**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**	31
Plan participant contributions		**-**	**1**	-	1	**16**	18
Benefits paid		**(654)**	**(162)**	(241)	(151)	**(40)**	(49)
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)**	(170)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2021		2020		**2021**	2020
	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)**	(39)
Noncurrent liabilities	**(232)**	**(288)**	(722)	(345)	**(103)**	(131)
Total recognized	**$ (260)**	**688**	(778)	390	**(137)**	(170)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**2.80 %**	**2.15**	2.30	1.80	**2.65**	2.15
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**	3.10
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 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.

During 2021, the actuarial gains related to the benefit obligations for U.S. and international plans were primarily related to an increase in the discount rates. During 2020 and 2019, the actuarial losses related to the benefit obligations for 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.	Int'l.
Pension Plans with Projected Benefit Obligation in Excess of Plan Assets				
Projected benefit obligation	$ **261**	**362**	2,548	391
Fair value of plan assets	**-**	**58**	1,770	35
Pension Plans with Accumulated Benefit Obligation in Excess of Plan Assets				
Accumulated benefit obligation	$ **234**	**271**	2,359	338
Fair value of plan assets	**-**	**9**	1,770	35

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	
	2021		2020		**2021**	2020
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial loss (gain)	$ **188**	**86**	467	326	**(1)**	14
Unrecognized prior service cost (credit)	**-**	**1**	-	-	**(145)**	(182)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2021		2020		**2021**	2020
	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**	(7)
Amortization of actuarial loss included in income (loss)*	**145**	**33**	95	21	**-**	1
Net change during the period	$ **279**	**240**	12	(99)	**16**	(6)
Prior service credit (cost) arising during the period	$ **-**	**-**	-	(1)	**-**	30
Amortization of prior service (credit) included in income (loss)	**-**	**(1)**	-	(1)	**(37)**	(31)
Net change during the period	$ **-**	**(1)**	-	(2)	**(37)**	(1)

**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	2019
	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	1
Interest cost	**53**	**79**	66	85	79	97	**4**	6	8
Expected return on plan assets	**(80)**	**(120)**	(85)	(145)	(74)	(138)	**-**	-	-
Amortization of prior service credit	**-**	**(1)**	-	(1)	-	(2)	**(37)**	(31)	(33)
Recognized net actuarial loss (gain)	**43**	**33**	51	22	54	32	**-**	1	(2)
Settlements loss (gain)	**102**	**-**	44	(1)	62	-	**-**	-	-
Curtailment loss	**12**	**-**	-	-	-	-	**-**	-	-
Net periodic benefit cost	**$ 203**	**52**	161	14	200	58	**(31)**	(22)	(26)

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.

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 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 non-pension 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 6.5 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 the 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 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, 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 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
2021									
Equity securities									
U.S.	$	**3**	**-**	**5**	**8**	**-**	**-**	**-**	**-**
International		**42**	**-**	**-**	**42**	**-**	**-**	**-**	**-**
Mutual funds		**17**	**-**	**-**	**17**	**236**	**403**	**-**	**639**
Debt securities									
Corporate		**-**	**1**	**-**	**1**	**-**	**-**	**-**	**-**
Mutual funds		**-**	**-**	**-**	**-**	**511**	**-**	**-**	**511**
Cash and cash equivalents		**-**	**-**	**-**	**-**	**68**	**-**	**-**	**68**
Real estate		**-**	**-**	**-**	**-**	**-**	**-**	**157**	**157**
Total in fair value hierarchy	$	**62**	**1**	**5**	**68**	**815**	**403**	**157**	**1,375**
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$				**394**				**417**
Debt securities									
Common/collective trusts					**1,073**				**3,015**
Cash and cash equivalents					**9**				**-**
Real estate					**36**				**1**
Total**	$	**62**	**1**	**5**	**1,580**	**815**	**403**	**157**	**4,808**

**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 $83 million and net receivables related to security 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	Total
2020									
Equity securities									
U.S.	$	-	3	5	8	-	-	-	-
International		99	-	-	99	-	-	-	-
Mutual funds		72	-	-	72	235	384	-	619
Debt securities									
Corporate		-	1	-	1	-	-	-	-
Mutual funds		-	-	-	-	455	-	-	455
Cash and cash equivalents		-	-	-	-	74	-	-	74
Derivatives		-	-	-	-	6	-	-	6
Real estate		-	-	-	-	-	-	142	142
Total in fair value hierarchy	$	171	4	5	180	770	384	142	1,296
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$				678				372
Debt securities									
Common/collective trusts					730				3,007
Cash and cash equivalents					8				-
Real estate					79				112
Total**	$	171	4	5	1,675	770	384	142	4,787

**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.*

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 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $80 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.	
2022	$	369	152	21
2023		185	152	18
2024		176	158	15
2025		154	162	14
2026		144	164	12
2027–2031		557	893	44

The following table summarizes our severance accrual activity:

	Millions of Dollars			
		2021	2020	2019
Balance at January 1	$	**24**	23	48
Accruals		**170**	14	(1)
Benefit payments		**(116)**	(13)	(24)
Balance at December 31	**$**	**78**	24	23

Accruals include severance costs associated with our company-wide restructuring program. Of the remaining balance at December 31, 2021, $43 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 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 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 own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $26 million in 2021, $25 million in 2020, and $30 million in 2019.

Share-Based Compensation Plans

The 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2014, replacing similar prior plans and providing that no new awards shall be granted under the prior plans. 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 Plan or 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. 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 net income (loss) and the associated tax benefit were:

	Millions of Dollars		
	2021	2020	2019
Compensation cost	**$ 304**	159	274
Tax benefit	**76**	40	71

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:

			Millions of Dollars
	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding at December 31, 2020	16,922,525	$ 55.12	$ 22
Exercised	**(3,846,361)**	**51.40**	**68**
Expired or cancelled	**(1,102,381)**	**53.47**	
Outstanding at December 31, 2021	**11,973,783**	**$ 56.46**	**$ 188**
Vested at December 31, 2021	**11,973,783**	**$ 56.46**	**$ 188**
Exercisable at December 31, 2021	**11,973,783**	**$ 56.46**	**$ 188**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2021, were all 3.06 years. The aggregate intrinsic value of options exercised was $23 million in 2020 and $39 million in 2019.

During 2021, we received $198 million in cash and realized a tax benefit of $15 million from the exercise of options. At December 31, 2021, 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 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 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:

		Weighted-Average	Millions of Dollars
	Stock Units	Grant Date Fair Value	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**	**$ 144**
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 being 2.59 years. The weighted-average grant date fair value of stock unit awards granted during 2020 and 2019 was $57.40 and $67.77, 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, 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. 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, 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**	**$ 20**
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 for the unvested cash-settled units. The weighted-average grant date fair value of stock unit awards granted during 2020 and 2019 were $41.59 and $68.20, respectively. The total fair value of stock units issued during 2020 and 2019 were negligible and $6 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 effective 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, 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**	**$ 18**
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 the unvested stock-settled performance shares. The weighted-average grant date fair value of stock-settled PSUs granted during 2020 and 2019 was $58.61 and $68.90, respectively. The total fair value of stock-settled PSUs 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 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, 2021:

			Millions of Dollars
	Stock Units	Weighted-Average Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2020	124,529	$ 39.95	
Granted	**1,073,228**	**46.65**	
Settled	**(1,080,078)**	**48.13**	**$ 52**
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 $68.90, respectively. The total fair value of cash-settled performance share awards settled during 2020 and 2019 was $116 million and $171 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:

		Weighted-Average	Millions of Dollars
	Stock Units	Grant Date Fair Value	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**	**$ 8**
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 $11 million, respectively.

Note 17—Income Taxes

Components of income tax provision (benefit) were:

		Millions of Dollars		
		2021	2020	2019
Income Taxes				
Federal				
Current	$	**32**	3	18
Deferred		**1,161**	(625)	(113)
Foreign				
Current		**3,128**	350	2,545
Deferred		**66**	(70)	(323)
State and local				
Current		**127**	(4)	148
Deferred		**119**	(139)	(8)
Total tax provision (benefit)	$	**4,633**	(485)	2,267

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	
		2021	2020
Deferred Tax Liabilities			
PP&E and intangibles	$	**10,170**	7,744
Inventory		**44**	64
Other		**213**	242
Total deferred tax liabilities		**10,427**	8,050
Deferred Tax Assets			
Benefit plan accruals		**321**	540
Asset retirement obligations and accrued environmental costs		**2,297**	2,262
Investments in joint ventures		**1,684**	1,653
Other financial accruals and deferrals		**827**	907
Loss and credit carryforwards		**7,402**	8,904
Other		**399**	365
Total deferred tax assets		**12,930**	14,631
Less: valuation allowance		**(8,342)**	(9,965)
Total deferred tax assets net of valuation allowance		**4,588**	4,666
Net deferred tax liabilities	$	**5,839**	3,384

At December 31, 2021, noncurrent assets and liabilities included deferred taxes of $340 million and $6,179 million, respectively. At December 31, 2020, noncurrent assets and liabilities included deferred taxes of $363 million and $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 carryforwards of $1.9 billion. If not utilized, U.S. foreign tax credits and net operating losses will begin to expire in 2022.

Our overall deferred tax liability increased during 2021 by $1.1 billion due to our Concho acquisition. *See Note 3.*

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

	Millions of Dollars		
	2021	2020	2019
Balance at January 1	**$ 9,965**	10,214	3,040
Charged to expense (benefit)	**(45)**	460	(225)
Other*	**(1,578)**	(709)	7,399
Balance at December 31	**$ 8,342**	9,965	10,214

**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 certain 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 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 $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, 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	2019
Balance at January 1	$	**1,206**	1,177	1,081
Additions based on tax positions related to the current year		**15**	6	9
Additions for tax positions of prior years		**177**	67	120
Reductions for tax positions of prior years		**(5)**	(34)	(22)
Settlements		**-**	(9)	(9)
Lapse of statute		**(48)**	(1)	(2)
Balance at December 31	$	**1,345**	1,206	1,177

Included in the balance of unrecognized tax benefits for 2021, 2020 and 2019 were $1,261 million, $1,128 million and $1,100 million, respectively, which, if recognized, would impact our effective tax rate. The balance of the unrecognized tax benefits increased in 2021 mainly due to U.S. tax credits acquired through our Concho acquisition. 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 million and $42 million, respectively, net of accrued income taxes. Interest and penalties resulted in a 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 jurisdictions. 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 have audit periods close that could significantly impact our total unrecognized tax benefits. 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.

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.

The amounts of U.S. and foreign income (loss) before income taxes, with a reconciliation of tax at the federal statutory rate to the provision for income taxes, were:

	Millions of Dollars			Percent of Pre-Tax Income (Loss)		
	2021	2020	2019	**2021**	2020	2019
Income (loss) before income taxes						
United States	$ **8,024**	(3,587)	4,704	**63.1 %**	114.2	49.4
Foreign	**4,688**	447	4,820	**36.9**	(14.2)	50.6
	$ **12,712**	(3,140)	9,524	**100.0 %**	100.0	100.0
Federal statutory income tax	$ **2,670**	(659)	2,000	**21.0 %**	21.0	21.0
Non-U.S. effective tax rates	**1,915**	194	1,399	**15.1**	(6.2)	14.7
Tax impact of debt restructuring	**75**	-	-	**0.6**	-	-
Australia disposition	**-**	(349)	-	**-**	11.1	-
U.K. disposition	**-**	-	(732)	**-**	-	(7.7)
Recovery of outside basis	**(55)**	(22)	(77)	**(0.4)**	0.7	(0.8)
Adjustment to tax reserves	**(11)**	18	9	**(0.1)**	(0.6)	0.1
Adjustment to valuation allowance	**(45)**	460	(225)	**(0.4)**	(14.6)	(2.4)
State income tax	**194**	(112)	123	**1.5**	3.6	1.3
Malaysia Deepwater Incentive	**-**	-	(164)	**-**	-	(1.7)
Enhanced oil recovery credit	**(99)**	(6)	(27)	**(0.8)**	0.2	(0.3)
Other	**(11)**	(9)	(39)	**(0.1)**	0.3	(0.4)
Total	$ **4,633**	(485)	2,267	**36.4 %**	15.5	23.8

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 adjustment is 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 allowance related to the tax impact of the impairment of 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 assets 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 $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 a valuation allowance. 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 tax 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	Accumulated Other Comprehensive Loss
December 31, 2018	$ (361)	-	(5,702)	(6,063)
Other comprehensive income (loss)	51	-	695	746
Cumulative effect of adopting ASU No. 2018-02*	(40)	-	-	(40)
December 31, 2019	(350)	-	(5,007)	(5,357)
Other comprehensive income	(75)	2	212	139
December 31, 2020	(425)	2	(4,795)	(5,218)
Other comprehensive income (loss)	**394**	**(2)**	**(124)**	**268**
December 31, 2021	**$ (31)**	**-**	**(4,919)**	**(4,950)**

**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 the completion of our sale of two ConocoPhillips U.K. subsidiaries. *See Note 3*.

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

	Millions of Dollars	
	2021	2020
Defined Benefit Plans	**$ 109**	72
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	***$ 31***	*13*

See Note 16.

Note 19—Cash Flow Information

		Millions of Dollars		
		2021	2020	2019
Noncash Investing Activities				
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	$	**442**	(116)	205
Cash Payments				
Interest	$	**924**	785	810
Income taxes		**856**	905	2,905
Net Sales (Purchases) of Investments				
Short-term investments purchased	$	**(5,554)**	(12,435)	(4,902)
Short-term investments sold		**8,810**	12,015	2,138
Investments and long-term receivables purchased		**(279)**	(325)	(146)
Investments and long-term receivables sold		**114**	87	-
	$	**3,091**	(658)	(2,910)

The following items are included in the “Cash Flows from Operating Activities” section of our consolidated cash flows.

In 2021, we made a total of $297 million in contributions to our U.S. qualified pension plan. In 2019, 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 award 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	2019
Interest and Debt Expense				
Incurred				
Debt	$	**887**	788	799
Other		**59**	73	36
		946	861	835
Capitalized		**(62)**	(55)	(57)
Expensed	$	**884**	806	778
Other Income (Loss)				
Interest income	$	**33**	100	166
Gain (loss) on investment in Cenovus Energy*		**1,040**	(855)	649
Other, net		**130**	246	543
	$	**1,203**	(509)	1,358

**See Note 5.*

Research and Development Expenditures—expensed	$	**62**	75	82
Shipping and Handling Costs	$	**1,047**	857	1,008
Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**-**	-	-
Lower 48		**-**	-	-
Canada		**(1)**	(7)	5
Europe, Middle East and North Africa		**(11)**	(15)	-
Asia Pacific		**2**	(11)	31
Other International		**1**	2	1
Corporate and Other		**(7)**	(31)	21
	$	**(16)**	(62)	58

		Millions of Dollars	
		2021	2020
Properties, Plants and Equipment			
Proved properties*	$	**114,274** **	94,312
Unproved properties*		**10,993**	4,141
Other		**4,379**	3,653
Gross properties, plants and equipment		**129,646**	102,106
Less: Accumulated depreciation, depletion and amortization		**(64,735)****	(62,213)
Net properties, plants and equipment	$	**64,911**	39,893

**Proved and Unproved properties increased by $20.0 billion and $6.9 billion, respectively, in 2021 compared with 2020, primarily 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	2019
Operating revenues and other income	$	**88**	79	89
Purchases		**5**	-	38
Operating expenses and selling, general and administrative expenses		**196**	63	65
Net interest income*		**(2)**	(5)	(13)

**We paid interest to, or received interest from, various affiliates. See Note 4, for additional information on loans to 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	2019
Revenue from contracts with customers	$	**34,590**	13,662	26,106
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative		**11,500**	5,177	6,558
Financial derivative contracts		**(262)**	(55)	(97)
Consolidated sales and other operating revenues	$	**45,828**	18,784	32,567

Revenues from contracts outside the scope of ASC Topic 606 relate primarily to physical gas contracts at market prices which qualify as derivatives accounted for under ASC Topic 815, "Derivatives and Hedging," and for which we have not elected NPNS. There is no significant difference in contractual terms or the policy for recognition of revenue from these contracts and those within the scope of ASC Topic 606. The following disaggregation of revenues is provided in conjunction with *Note 23—Segment Disclosures and Related Information*:

		Millions of Dollars		
		2021	2020	2019
Revenue from Outside the Scope of ASC Topic 606 by Segment				
Lower 48	$	**9,050**	3,966	4,989
Canada		**1,457**	727	691
Europe, Middle East and North Africa		**993**	484	878
Physical contracts meeting the definition of a derivative	$	**11,500**	5,177	6,558

		Millions of Dollars		
		2021	2020	2019
Revenue from Outside the Scope of ASC Topic 606 by Product				
Crude oil	$	**757**	395	804
Natural gas		**10,034**	4,339	5,313
Other		**709**	443	441
Physical contracts meeting the definition of a derivative	$	**11,500**	5,177	6,558

Practical Expedients
Typically, our commodity sales contracts are less than 12 months in duration; however, in certain specific cases may extend longer, which may be out to the end of field life. We have long-term commodity sales contracts which use prevailing market prices at the time of delivery, and under these contracts, the market-based variable consideration for each performance obligation (i.e., delivery of commodity) is allocated to each wholly unsatisfied performance obligation within the contract. Accordingly, we have applied the practical expedient allowed in ASC Topic 606 and do not disclose the aggregate amount of the transaction price allocated to performance obligations or when we expect to recognize revenues that are unsatisfied (or partially unsatisfied) as of the end of the reporting period.

Receivables and Contract Liabilities

Receivables from Contracts with Customers
At December 31, 2021, the "Accounts and notes receivable" line on our consolidated balance sheet included trade receivables of $5,268 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) once delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical gas sales contracts at market prices for which we do not elect NPNS and are therefore accounted for as a derivative under ASC Topic 815. There is little distinction in the nature of the customer or credit quality of trade receivables associated with gas sold under contracts for which NPNS has not been elected compared with trade receivables where NPNS has been elected.

Contract Liabilities from Contracts with Customers
We have entered into contractual arrangements where we license proprietary technology to customers related to the optimization process for operating LNG plants. The agreements typically provide for negotiated payments to be made at stated milestones. The payments are not directly related to our performance under the contract and are recorded as deferred revenue to be recognized as revenue when the customer can utilize and benefit from their right to use the license. Payments are received in installments over the construction period.

	Millions of Dollars	
Contract Liabilities		
At December 31, 2020	$	**97**
Contractual payments received		**15**
Revenue recognized		**(62)**
At December 31, 2021	$	**50**
Amounts Recognized in the Consolidated Balance Sheet at December 31, 2021		
Current liabilities	$	**50**

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 NGLs on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska; Lower 48; Canada; Europe, 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 Texas 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	2019
Sales and Other Operating Revenues			
Alaska	$ **5,480**	3,408	5,483
Intersegment eliminations	**-**	(11)	-
Alaska	**5,480**	3,397	5,483
Lower 48	**29,306**	9,872	15,514
Intersegment eliminations	**(12)**	(51)	(46)
Lower 48	**29,294**	9,821	15,468
Canada	**4,077**	1,666	2,910
Intersegment eliminations	**(1,583)**	(405)	(1,141)
Canada	**2,494**	1,261	1,769
Europe, Middle East and North Africa	**5,902**	1,919	5,101
Intersegment eliminations	**-**	(2)	-
Europe, Middle East and North Africa	**5,902**	1,917	5,101
Asia Pacific	**2,579**	2,363	4,525
Other International	**4**	7	-
Corporate and Other	**75**	18	221
Consolidated sales and other operating revenues	$ **45,828**	18,784	32,567

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	2019
Depreciation, Depletion, Amortization and Impairments				
Alaska	**$**	**1,002**	996	805
Lower 48		**4,067**	3,358	3,224
Canada		**392**	342	232
Europe, Middle East and North Africa		**862**	775	887
Asia Pacific		**1,483**	809	1,285
Other International		**-**	-	-
Corporate and Other		**76**	54	62
Consolidated depreciation, depletion, amortization and impairments	**$**	**7,882**	6,334	6,495
Equity in Earnings of Affiliates				
Alaska	**$**	**5**	(7)	7
Lower 48		**(18)**	(11)	(159)
Canada		**-**	-	-
Europe, Middle East and North Africa		**502**	311	470
Asia Pacific		**343**	137	461
Other International		**-**	2	-
Corporate and Other		**-**	-	-
Consolidated equity in earnings of affiliates	**$**	**832**	432	779
Income Tax Provision (Benefit)				
Alaska	**$**	**402**	(256)	472
Lower 48		**1,390**	(378)	137
Canada		**150**	(185)	(43)
Europe, Middle East and North Africa		**2,543**	136	1,425
Asia Pacific		**483**	294	501
Other International		**(53)**	(20)	8
Corporate and Other		**(282)**	(76)	(233)
Consolidated income tax provision (benefit)	**$**	**4,633**	(485)	2,267
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	**$**	**1,386**	(719)	1,520
Lower 48		**4,932**	(1,122)	436
Canada		**458**	(326)	279
Europe, Middle East and North Africa		**1,167**	448	3,170
Asia Pacific		**453**	962	1,483
Other International		**(107)**	(64)	263
Corporate and Other		**(210)**	(1,880)	38
Consolidated net income (loss) attributable to ConocoPhillips	**$**	**8,079**	(2,701)	7,189

		Millions of Dollars		
		2021	2020	2019
Investments in and Advances to Affiliates				
Alaska	$	**58**	62	83
Lower 48		**242**	25	35
Canada		**-**	-	-
Europe, Middle East and North Africa		**797**	918	1,070
Asia Pacific		**5,603**	6,705	7,265
Other International		**1**	-	-
Corporate and Other		**-**	-	-
Consolidated investments in and advances to affiliates	$	**6,701**	7,710	8,453
Total Assets				
Alaska	$	**14,812**	14,623	15,453
Lower 48		**41,699**	11,932	14,425
Canada		**7,439**	6,863	6,350
Europe, Middle East and North Africa		**9,125**	8,756	9,269
Asia Pacific		**9,840**	11,231	13,568
Other International		**1**	226	285
Corporate and Other		**7,745**	8,987	11,164
Consolidated total assets	$	**90,661**	62,618	70,514
Capital Expenditures and Investments				
Alaska	$	**982**	1,038	1,513
Lower 48		**3,129**	1,881	3,394
Canada		**203**	651	368
Europe, Middle East and North Africa		**534**	600	708
Asia Pacific		**390**	384	584
Other International		**33**	121	8
Corporate and Other		**53**	40	61
Consolidated capital expenditures and investments	$	**5,324**	4,715	6,636
Interest Income and Expense				
Interest income				
Alaska	$	**-**	-	-
Lower 48		**-**	-	-
Canada		**-**	-	-
Europe, Middle East and North Africa		**2**	5	11
Asia Pacific		**9**	7	6
Other International		**-**	-	-
Corporate and Other		**22**	88	149
Interest and debt expense				
Corporate and Other	$	**884**	806	778
Sales and Other Operating Revenues by Product				
Crude oil	$	**23,648**	9,736	18,482
Natural gas		**16,904**	6,427	8,715
Natural gas liquids		**1,668**	528	814
Other*		**3,608**	2,093	4,556
Consolidated sales and other operating revenues by product	$	**45,828**	18,784	32,567

**Includes LNG and bitumen.*

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
	2021	2020	2019	**2021**	2020	2019
United States	$ **34,847**	13,230	21,159	**50,580**	24,034	26,566
Australia and Timor-Leste	**-**	605	1,647	**5,579**	6,676	7,228
Canada	**2,494**	1,261	1,769	**6,608**	6,385	5,769
China	**724**	460	772	**1,476**	1,491	1,447
Indonesia[3]	**879**	689	875	**28**	464	605
Libya	**1,102**	155	1,103	**659**	670	668
Malaysia	**975**	610	1,230	**1,252**	1,501	1,871
Norway	**2,563**	1,426	2,349	**4,681**	5,294	5,258
United Kingdom	**2,236**	336	1,649	**1**	1	2
Other foreign countries	**8**	12	14	**748**	1,087	1,308
Worldwide consolidated	$ **45,828**	18,784	32,567	**71,612**	47,603	50,722

(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 regulations of the SEC, we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. Our disclosures by geographic area include the U.S., Canada, Europe, Asia Pacific/Middle East (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, then our applicable reserve quantities would decline. At December 31, 2021, approximately 4 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.

Reserves Governance

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

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

We have a company-wide, 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 2021, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2021, 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, 2021, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M's report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company's reserves estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master's degree in petroleum engineering. He is a member of the Society of Petroleum Engineers with over 25 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the U.S. and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

Proved Reserves

Years Ended December 31	Crude Oil Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2018	1,233	703	1,936	4	246	159	188	2,533
Revisions	40	(36)	4	(1)	18	(5)	23	39
Improved recovery	7	-	7	-	-	-	-	7
Purchases	-	1	1	-	-	-	-	1
Extensions and discoveries	25	226	251	2	-	11	-	264
Production	(74)	(95)	(169)	-	(36)	(31)	(14)	(250)
Sales	-	(2)	(2)	-	(30)	-	-	(32)
End of 2019	1,231	797	2,028	5	198	134	197	2,562
Revisions	(297)	(126)	(423)	(2)	4	(4)	(3)	(428)
Improved recovery	-	-	-	-	-	3	-	3
Purchases	-	5	5	3	-	-	-	8
Extensions and discoveries	10	108	118	3	-	-	-	121
Production	(65)	(77)	(142)	(2)	(28)	(25)	(3)	(200)
Sales	-	(14)	(14)	(1)	-	-	-	(15)
End of 2020	879	693	1,572	6	174	108	191	2,051
Revisions	209	(52)	157	2	14	37	6	216
Improved recovery	1	-	1	-	-	-	-	1
Purchases	-	691	691	-	-	-	-	691
Extensions and discoveries	10	289	299	5	2	1	-	307
Production	(64)	(160)	(224)	(3)	(29)	(24)	(13)	(293)
Sales	-	(9)	(9)	-	-	-	-	(9)
End of 2021	1,035	1,452	2,487	10	161	122	184	2,964
Equity affiliates								
End of 2018	-	-	-	-	-	78	-	78
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	73	-	73
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	68	-	68
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	63	-	63
Total company								
End of 2018	1,233	703	1,936	4	246	237	188	2,611
End of 2019	1,231	797	2,028	5	198	207	197	2,635
End of 2020	879	693	1,572	6	174	176	191	2,119
End of 2021	1,035	1,452	2,487	10	161	185	184	3,027

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 2018	1,058	346	1,404	2	192	113	185	1,896
End of 2019	1,048	334	1,382	3	149	94	181	1,809
End of 2020	765	263	1,028	6	129	77	175	1,415
End of 2021	912	916	1,828	4	122	98	171	2,223
Equity affiliates								
End of 2018	-	-	-	-	-	78	-	78
End of 2019	-	-	-	-	-	73	-	73
End of 2020	-	-	-	-	-	68	-	68
End of 2021	-	-	-	-	-	63	-	63
Undeveloped								
Consolidated operations								
End of 2018	175	357	532	2	54	46	3	637
End of 2019	183	463	646	2	49	40	16	753
End of 2020	114	430	544	-	45	31	16	636
End of 2021	123	536	659	6	39	24	13	741
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, included:

- *Revisions*: In 2021, Alaska upward revisions were primarily driven by higher prices. Downward revisions in Lower 48 were due to development timing for specific well locations from unconventional plays of 203 million barrels and technical revisions of 35 million barrels, partially offset by upward revisions due to higher prices of 115 million barrels and additional infill drilling in the unconventional plays of 71 million barrels. Upward revisions in Europe were primarily due to higher prices. In Asia Pacific/Middle East, increases were due to higher prices of 21 million barrels and technical revisions of 16 million barrels.

  In 2020, Alaska downward revisions were primarily driven by lower prices of 243 million barrels and development plan changes of 54 million barrels. Downward revisions in Lower 48 were due to lower prices of 89 million barrels and development timing for specific well locations from unconventional plays of 82 million barrels, partially offset by upward technical revisions and additional infill drilling in the unconventional plays of 45 million barrels.

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

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

- *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 resulting from development plan timing in the revisions category.

  In 2020, 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 resulting from development plan timing in the revisions category.

  In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locations from the unconventional plays which more than offset the decreases in the revisions category. In Asia Pacific/Middle East, increases were due to sanctioning of development programs in China and Malaysia.

- *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 Pacific/ Middle East	Total
Developed and Undeveloped							
Consolidated operations							
End of 2018	106	222	328	1	17	3	349
Revisions	(1)	(11)	(12)	-	3	(1)	(10)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	62	62	1	-	-	63
Production	(5)	(28)	(33)	-	(3)	(1)	(37)
Sales	-	-	-	-	(4)	-	(4)
End of 2019	100	245	345	2	13	1	361
Revisions	-	(26)	(26)	-	1	(1)	(26)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	2	2	2	-	-	4
Extensions and discoveries	-	41	41	1	-	-	42
Production	(6)	(27)	(33)	(1)	(2)	-	(36)
Sales	-	(5)	(5)	-	-	-	(5)
End of 2020	94	230	324	4	12	-	340
Revisions	(6)	213	207	-	1	-	208
Improved recovery	-	-	-	-	-	-	-
Purchases	-	72	72	-	-	-	72
Extensions and discoveries	-	82	82	2	-	-	84
Production	(6)	(50)	(56)	(1)	(2)	-	(59)
Sales	-	(1)	(1)	-	-	-	(1)
End of 2021	82	546	628	5	11	-	644
Equity affiliates							
End of 2018	-	-	-	-	-	42	42
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	39	39
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	36	36
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	33	33
Total company							
End of 2018	106	222	328	1	17	45	391
End of 2019	100	245	345	2	13	40	400
End of 2020	94	230	324	4	12	36	376
End of 2021	82	546	628	5	11	33	677

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 2018	106	97	203	-	15	3	221
End of 2019	100	99	199	1	10	1	211
End of 2020	94	83	177	4	9	-	190
End of 2021	82	334	416	3	9	-	428
Equity affiliates							
End of 2018	-	-	-	-	-	42	42
End of 2019	-	-	-	-	-	39	39
End of 2020	-	-	-	-	-	36	36
End of 2021	-	-	-	-	-	33	33
Undeveloped							
Consolidated operations							
End of 2018	-	125	125	1	2	-	128
End of 2019	-	146	146	1	3	-	150
End of 2020	-	147	147	-	3	-	150
End of 2021	-	212	212	2	2	-	216
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 Permian two-stream contracts to a three-stream (crude oil, natural gas and natural gas liquids) basis, adding 182 million barrels, additional infill drilling in the unconventional plays of 44 million barrels, technical revisions of 21 million barrels and higher prices of 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 development timing for specific well locations from unconventional plays of 20 million barrels, partially offset by upward technical 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 locations from the unconventional plays of 32 million barrels and price revisions of 11 million barrels, partially offset by upward revisions related to infill drilling and improved well performance of 32 million barrels.

- *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 planned development to add specific well locations from the unconventional plays which more than offset the decreases in the revisions category.

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

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

- *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	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2018	2,736	2,318	5,054	26	1,212	1,079	214	7,585
Revisions	30	(113)	(83)	(2)	160	147	21	243
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	2	2	-	-	-	-	2
Extensions and discoveries	7	483	490	23	-	1	-	514
Production	(85)	(252)	(337)	(4)	(178)	(250)	(11)	(780)
Sales	-	(7)	(7)	-	(298)	-	-	(305)
End of 2019	2,688	2,431	5,119	43	896	977	224	7,259
Revisions	(607)	(439)	(1,046)	(15)	39	103	2	(917)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	74	74	29	-	-	-	103
Extensions and discoveries	-	304	304	33	2	-	-	339
Production	(85)	(231)	(316)	(16)	(112)	(171)	(2)	(617)
Sales	-	(39)	(39)	-	-	(58)	-	(97)
End of 2020	1,996	2,100	4,096	74	825	851	224	6,070
Revisions	715	41	756	15	54	60	-	885
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	2,438	2,438	-	-	-	-	2,438
Extensions and discoveries	-	822	822	46	2	-	-	870
Production	(86)	(473)	(559)	(30)	(113)	(147)	(7)	(856)
Sales	-	(270)	(270)	-	-	-	-	(270)
End of 2021	2,625	4,658	7,283	105	768	764	217	9,137
Equity affiliates								
End of 2018	-	-	-	-	-	4,564	-	4,564
Revisions	-	-	-	-	-	(7)	-	(7)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	252	-	252
Production	-	-	-	-	-	(388)	-	(388)
Sales	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	4,421	-	4,421
Revisions	-	-	-	-	-	(382)	-	(382)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	2	-	2
Extensions and discoveries	-	-	-	-	-	78	-	78
Production	-	-	-	-	-	(395)	-	(395)
Sales	-	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	3,724	-	3,724
Revisions	-	-	-	-	-	247	-	247
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	116	-	116
Production	-	-	-	-	-	(390)	-	(390)
Sales	-	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	3,697	-	3,697
Total company								
End of 2018	2,736	2,318	5,054	26	1,212	5,643	214	12,149
End of 2019	2,688	2,431	5,119	43	896	5,398	224	11,680
End of 2020	1,996	2,100	4,096	74	825	4,575	224	9,794
End of 2021	2,625	4,658	7,283	105	768	4,461	217	12,834

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 2018	2,720	1,427	4,147	17	1,052	758	214	6,188
End of 2019	2,601	1,398	3,999	30	697	843	224	5,793
End of 2020	1,961	1,051	3,012	74	598	806	224	4,714
End of 2021	2,579	3,100	5,679	52	679	688	217	7,315
Equity affiliates								
End of 2018	-	-	-	-	-	4,059	-	4,059
End of 2019	-	-	-	-	-	3,898	-	3,898
End of 2020	-	-	-	-	-	3,293	-	3,293
End of 2021	-	-	-	-	-	3,204	-	3,204
Undeveloped								
Consolidated operations								
End of 2018	16	891	907	9	160	321	-	1,397
End of 2019	87	1,033	1,120	13	199	134	-	1,466
End of 2020	35	1,049	1,084	-	227	45	-	1,356
End of 2021	46	1,558	1,604	53	89	76	-	1,822
Equity affiliates								
End of 2018	-	-	-	-	-	505	-	505
End of 2019	-	-	-	-	-	523	-	523
End of 2020	-	-	-	-	-	431	-	431
End of 2021	-	-	-	-	-	493	-	493

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations. Quantities consumed in production operations are not significant in the periods presented. The value of net production consumed in operations is not reflected in net revenues and production expenses, nor do the volumes impact the respective per unit metrics.

Reserve volumes include natural gas to be consumed in operations of 2,748 Bcf, 2,286 Bcf and 3,141 Bcf, as of December 31, 2021, 2020 and 2019, respectively. These volumes are not included in the calculation of our Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

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

- *Revisions*: In 2021, upward revisions in Alaska were due to higher prices of 587 Bcf and technical revisions of 128 Bcf. In Lower 48, upward revisions of 614 Bcf were due to higher prices, additional infill drilling in the unconventional plays of 277 Bcf and technical revisions of 60 Bcf, partially offset by downward revisions due to development timing for specific well locations from unconventional plays of 498 Bcf and conversion of previously acquired Permian two-stream contracted volumes to a three-stream (crude oil, natural gas and natural gas liquids) basis of 412 Bcf. Upward revisions in Canada were due to higher prices of 29 Bcf, partially offset by downward revisions due to technical revisions of 14 Bcf. In Europe, upward revisions were primarily due to higher prices. Upward revisions in our consolidated operations in Asia Pacific/Middle East were due to technical revisions of 76 Bcf, partially offset by price revisions of 16 Bcf. In our equity affiliates in Asia Pacific/Middle East, upward revisions were due to higher prices of 124 Bcf and technical and cost revisions of 123 Bcf.

  In 2020, downward revisions in Alaska were primarily due to lower prices. In Lower 48, downward revisions of 372 Bcf were due to lower prices and 154 Bcf were due to development timing for specific well locations from unconventional plays, partially offset by technical revisions of 87 Bcf. Downward revisions in our equity affiliates in Asia Pacific/Middle East were due to lower prices of 426 Bcf, partially offset by performance revisions of 44 Bcf. Upward revisions in our consolidated operations in Asia Pacific/Middle East were due to technical revisions of 88 Bcf and price revisions of 15 Bcf.

In 2019, upward revisions in Europe were due to technical and cost revisions. In Asia Pacific/Middle East upward revisions were primarily due to the Indonesia Corridor PSC term extension. Downward revisions in Lower 48 were due to changes in development timing for specific well locations from the unconventional plays of 207 Bcf and price revisions of 125 Bcf, partially offset by upward revisions related to infill drilling and improved well performance of 219 Bcf.

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

  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 resulting from development plan timing in the revisions category. Extensions and discoveries in Canada were primarily driven by ongoing drilling successes in Montney.

  In 2020, 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 resulting from development plan timing in the revisions category. Extensions and discoveries in Canada were primarily driven by ongoing drilling successes in Montney.

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

- *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 assets.

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

Years Ended December 31	Bitumen Millions of Barrels Canada
Developed and Undeveloped	
Consolidated operations	
End of 2018	236
Revisions	37
Improved recovery	-
Purchases	-
Extensions and discoveries	31
Production	(22)
Sales	-
End of 2019	282
Revisions	(15)
Improved recovery	-
Purchases	-
Extensions and discoveries	85
Production	(20)
Sales	-
End of 2020	332
Revisions	(50)
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(25)
Sales	-
End of 2021	257
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	236
End of 2019	282
End of 2020	332
End of 2021	257

Years Ended December 31	Bitumen Millions of Barrels Canada
Developed	
Consolidated operations	
End of 2018	155
End of 2019	187
End of 2020	117
End of 2021	150
Equity affiliates	
End of 2018	-
End of 2019	-
End of 2020	-
End of 2021	-
Undeveloped	
Consolidated operations	
End of 2018	81
End of 2019	95
End of 2020	215
End of 2021	107
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, included:

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

  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 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.

- *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 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	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2018	1,795	1,312	3,107	245	465	342	224	4,383
Revisions	44	(67)	(23)	36	48	19	26	106
Improved recovery	7	-	7	-	-	-	-	7
Purchases	-	2	2	-	-	-	-	2
Extensions and discoveries	26	368	394	38	-	11	-	443
Production	(93)	(165)	(258)	(23)	(68)	(74)	(16)	(439)
Sales	-	(3)	(3)	-	(85)	-	-	(88)
End of 2019	1,779	1,447	3,226	296	360	298	234	4,414
Revisions	(398)	(226)	(624)	(20)	12	13	(3)	(622)
Improved recovery	-	-	-	-	-	3	-	3
Purchases	-	19	19	10	-	-	-	29
Extensions and discoveries	10	200	210	95	-	-	-	305
Production	(85)	(142)	(227)	(25)	(49)	(55)	(3)	(359)
Sales	-	(25)	(25)	(1)	-	(10)	-	(36)
End of 2020	1,306	1,273	2,579	355	323	249	228	3,734
Revisions	322	168	490	(45)	23	47	6	521
Improved recovery	1	-	1	-	-	-	-	1
Purchases	-	1,169	1,169	-	-	-	-	1,169
Extensions and discoveries	10	508	518	15	3	1	-	537
Production	(84)	(289)	(373)	(35)	(50)	(48)	(14)	(520)
Sales	-	(54)	(54)	-	-	-	-	(54)
End of 2021	1,555	2,775	4,330	290	299	249	220	5,388
Equity affiliates								
End of 2018	-	-	-	-	-	880	-	880
Revisions	-	-	-	-	-	(1)	-	(1)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	42	-	42
Production	-	-	-	-	-	(73)	-	(73)
Sales	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	848	-	848
Revisions	-	-	-	-	-	(63)	-	(63)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	13	-	13
Production	-	-	-	-	-	(73)	-	(73)
Sales	-	-	-	-	-	-	-	-
End of 2020	-	-	-	-	-	725	-	725
Revisions	-	-	-	-	-	42	-	42
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	19	-	19
Production	-	-	-	-	-	(73)	-	(73)
Sales	-	-	-	-	-	-	-	-
End of 2021	-	-	-	-	-	713	-	713
Total company								
End of 2018	1,795	1,312	3,107	245	465	1,222	224	5,263
End of 2019	1,779	1,447	3,226	296	360	1,146	234	5,262
End of 2020	1,306	1,273	2,579	355	323	974	228	4,459
End of 2021	1,555	2,775	4,330	290	299	962	220	6,101

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 2018	1,617	681	2,298	160	382	244	221	3,305
End of 2019	1,582	666	2,248	197	275	236	218	3,174
End of 2020	1,186	521	1,707	140	238	211	212	2,508
End of 2021	1,424	1,767	3,191	166	244	212	207	4,020
Equity affiliates								
End of 2018	-	-	-	-	-	796	-	796
End of 2019	-	-	-	-	-	761	-	761
End of 2020	-	-	-	-	-	653	-	653
End of 2021	-	-	-	-	-	631	-	631
Undeveloped								
Consolidated operations								
End of 2018	178	631	809	85	83	98	3	1,078
End of 2019	197	781	978	99	85	62	16	1,240
End of 2020	120	752	872	215	85	38	16	1,226
End of 2021	131	1,008	1,139	124	55	37	13	1,368
Equity affiliates								
End of 2018	-	-	-	-	-	84	-	84
End of 2019	-	-	-	-	-	87	-	87
End of 2020	-	-	-	-	-	72	-	72
End of 2021	-	-	-	-	-	82	-	82

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

Proved Undeveloped Reserves

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

	Proved Undeveloped Reserves
	Millions of Barrels of Oil Equivalent
End of 2020	1,298
Revisions	(167)
Improved recovery	1
Purchases	158
Extensions and discoveries	448
Sales	-
Transfers to proved developed	(288)
End of 2021	1,450

Downward revisions were driven by changes in development timing of 389 MMBOE primarily in North America and negative bitumen revisions in Canada due to changes in carbon tax costs of 65 MMBOE, partially offset by upward revisions 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 continued development of unconventional plays. The remaining extensions and discoveries were driven by the continued development planned in the other geographic regions.

Transfers to proved developed reserves were driven by the ongoing development of our assets. Approximately 65 percent of the transfers were from the development of our Lower 48 unconventional plays. The remainder of transfers were from development across the other geographic regions.

At December 31, 2021, our PUDs represented 24 percent of total proved reserves, compared with 29 percent at December 31, 2020. Costs incurred for the year ended December 31, 2021, relating to the development of PUDs were $3.8 billion. A portion of our costs incurred each year relates to development projects where the PUDs will be converted to proved developed reserves in future years.

At the end of 2021, approximately 93 percent of total PUDs were under development or scheduled for development within five years of initial disclosure, including all of our Lower 48 PUDs. The remaining PUDs are in major development 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 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, LNG operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company's net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.
- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.
- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.
- Taxes other than income taxes include production, property and other non-income taxes.
- Depreciation of support equipment is reclassified as applicable.
- Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

Results of Operations

Year Ended December 31, 2021	Millions of Dollars									
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations										
Sales	$	4,832	14,093	18,925	1,219	3,568	2,525	917	-	27,154
Transfers		4	-	4	-	-	-	-	-	4
Transportation costs		(626)	-	(626)	-	-	-	-	-	(626)
Other revenues		14	135	149	323	(5)	237	141	(161)	684
Total revenues		4,224	14,228	18,452	1,542	3,563	2,762	1,058	(161)	27,216
Production costs excluding taxes		1,073	2,414	3,487	518	487	466	43	-	5,001
Taxes other than income taxes		442	937	1,379	23	36	91	1	1	1,531
Exploration expenses		80	98	178	39	21	51	2	15	306
Depreciation, depletion and amortization		864	4,053	4,917	383	844	787	35	-	6,966
Impairments		5	(8)	(3)	6	(24)	7	-	-	(14)
Other related expenses		(31)	12	(19)	(22)	(42)	4	4	12	(63)
Accretion		71	47	118	10	70	26	-	-	224
		1,720	6,675	8,395	585	2,171	1,330	973	(189)	13,265
Income tax provision (benefit)		378	1,467	1,845	145	1,673	494	870	(53)	4,974
Results of operations	$	1,342	5,208	6,550	440	498	836	103	(136)	8,291
Equity affiliates										
Sales	$	-	-	-	-	-	745	-	-	745
Transfers		-	-	-	-	-	1,797	-	-	1,797
Transportation costs		-	-	-	-	-	-	-	-	-
Other revenues		-	-	-	-	-	5	-	-	5
Total revenues		-	-	-	-	-	2,547	-	-	2,547
Production costs excluding taxes		-	-	-	-	-	329	-	-	329
Taxes other than income taxes		-	-	-	-	-	824	-	-	824
Exploration expenses		-	-	-	-	-	268	-	-	268
Depreciation, depletion and amortization		-	-	-	-	-	593			593
Impairments		-	-	-	-	-	718	-	-	718
Other related expenses		-	-	-	-	-	3	-	-	3
Accretion		-	-	-	-	-	17	-	-	17
		-	-	-	-	-	(205)	-	-	(205)
Income tax provision (benefit)		-	-	-	-	-	(42)	-	-	(42)
Results of operations	$	-	-	-	-	-	(163)	-	-	(163)

Year Ended December 31, 2020									
	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations									
Sales	$ 2,944	3,421	6,365	230	1,560	1,717	129	-	10,001
Transfers	4	-	4	-	-	191	-	-	195
Transportation costs	(587)	-	(587)	-	-	(19)	-	-	(606)
Other revenues	(1)	(20)	(21)	40	(21)	576	11	10	595
Total revenues	2,360	3,401	5,761	270	1,539	2,465	140	10	10,185
Production costs excluding taxes	1,058	1,399	2,457	366	417	478	21	2	3,741
Taxes other than income taxes	296	263	559	16	30	42	3	1	651
Exploration expenses	1,099	73	1,172	40	52	71	13	108	1,456
Depreciation, depletion and amortization	840	2,544	3,384	335	755	808	8	-	5,290
Impairments	-	804	804	3	5	-	-	-	812
Other related expenses	46	5	51	5	(58)	(25)	(29)	2	(54)
Accretion	72	46	118	8	73	33	-	-	232
	(1,051)	(1,733)	(2,784)	(503)	265	1,058	124	(103)	(1,943)
Income tax provision (benefit)	(271)	(430)	(701)	(191)	116	277	88	(20)	(431)
Results of operations	$ (780)	(1,303)	(2,083)	(312)	149	781	36	(83)	(1,512)
Equity affiliates									
Sales	$ -	-	-	-	-	483	-	-	483
Transfers	-	-	-	-	-	1,205	-	-	1,205
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	8	-	-	8
Total revenues	-	-	-	-	-	1,696	-	-	1,696
Production costs excluding taxes	-	-	-	-	-	289	-	-	289
Taxes other than income taxes	-	-	-	-	-	502	-	-	502
Exploration expenses	-	-	-	-	-	20	-	-	20
Depreciation, depletion and amortization	-	-	-	-	-	569	-	-	569
Impairments	-	-	-	-	-	-	-	-	-
Other related expenses	-	-	-	-	-	(2)	-	-	(2)
Accretion	-	-	-	-	-	15	-	-	15
	-	-	-	-	-	303	-	-	303
Income tax provision (benefit)	-	-	-	-	-	39	-	-	39
Results of operations	$ -	-	-	-	-	264	-	-	264

Year Ended December 31, 2019	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations									
Sales	$ 4,883	6,356	11,239	709	3,207	3,032	919	-	19,106
Transfers	4	-	4	-	-	449	-	-	453
Transportation costs	(629)	-	(629)	-	-	(41)	-	-	(670)
Other revenues	61	78	139	86	1,785	12	101	326	2,449
Total revenues	4,319	6,434	10,753	795	4,992	3,452	1,020	326	21,338
Production costs excluding taxes	1,235	1,578	2,813	380	741	619	70	(8)	4,615
Taxes other than income taxes	308	437	745	18	32	54	3	(2)	850
Exploration expenses	97	430	527	32	69	80	5	33	746
Depreciation, depletion and amortization	700	2,804	3,504	230	842	1,172	37	-	5,785
Impairments	-	402	402	2	1	-	-	-	405
Other related expenses	(12)	116	104	(38)	(42)	58	22	10	114
Accretion	62	49	111	7	142	43	-	-	303
	1,929	618	2,547	164	3,207	1,426	883	293	8,520
Income tax provision (benefit)	444	147	591	(74)	591	458	833	7	2,406
Results of operations	$ 1,485	471	1,956	238	2,616	968	50	286	6,114
Equity affiliates									
Sales	$ -	-	-	-	-	599	-	-	599
Transfers	-	-	-	-	-	2,229	-	-	2,229
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	31	-	-	31
Total revenues	-	-	-	-	-	2,859	-	-	2,859
Production costs excluding taxes	-	-	-	-	-	335	-	-	335
Taxes other than income taxes	-	-	-	-	-	820	-	-	820
Exploration expenses	-	-	-	-	-	-	-	-	-
Depreciation, depletion and amortization	-	-	-	-	-	579	-	-	579
Impairments	-	-	-	-	-	-	-	-	-
Other related expenses	-	-	-	-	-	11	-	-	11
Accretion	-	-	-	-	-	16	-	-	16
	-	-	-	-	-	1,098	-	-	1,098
Income tax provision (benefit)	-	-	-	-	-	170	-	-	170
Results of operations	$ -	-	-	-	-	928	-	-	928

Statistics

Net Production	**2021**	2020	2019
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**178**	181	202
Lower 48	**447**	213	266
United States	**625**	394	468
Canada	**8**	6	1
Europe	**81**	78	100
Asia Pacific	**65**	69	85
Africa	**37**	8	38
Total consolidated operations	**816**	555	692
Equity affiliates—Asia Pacific/Middle East	**13**	13	13
Total company	**829**	568	705
*Delaware Basin Area (Lower 48)**	***162***	*28*	*24*
*Greater Prudhoe Area (Alaska)**	***67***	*68*	*66*
Natural Gas Liquids			
Consolidated operations			
Alaska	**16**	16	15
Lower 48	**110**	74	81
United States	**126**	90	96
Canada	**4**	2	-
Europe	**4**	4	7
Asia Pacific	**-**	1	4
Total consolidated operations	**134**	97	107
Equity affiliates—Asia Pacific/Middle East	**8**	8	8
Total company	**142**	105	115
*Delaware Basin Area (Lower 48)**	***27***	*11*	*11*
*Greater Prudhoe Area (Alaska)**	***16***	*15*	*15*
Bitumen			
Consolidated operations—Canada	**69**	55	60
Total company	**69**	55	60
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**16**	10	7
Lower 48	**1,340**	585	622
United States	**1,356**	595	629
Canada	**80**	40	9
Europe	**298**	270	447
Asia Pacific	**360**	429	637
Africa	**15**	5	31
Total consolidated operations	**2,109**	1,339	1,753
Equity affiliates—Asia Pacific/Middle East	**1,053**	1,055	1,052
Total company	**3,162**	2,394	2,805
*Delaware Basin Area (Lower 48)**	***584***	*99*	*86*
*Greater Prudhoe Area (Alaska)**	***12***	*4*	*4*

**At year-end 2021, the Delaware Basin Area in Lower 48 contained more than 15 percent of our total proved reserves. At year-end 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	2019
Crude Oil Per Barrel				
Consolidated operations				
Alaska*	$	**60.81**	33.72	55.85
Lower 48		**66.12**	35.17	55.30
United States		**64.53**	34.48	55.54
Canada		**56.38**	23.57	40.87
Europe		**68.94**	42.80	65.12
Asia Pacific		**70.36**	42.84	65.02
Africa		**69.06**	48.64	64.47
Total international		**68.85**	42.39	64.85
Total consolidated operations		**65.53**	36.69	58.51
Equity affiliates—Asia Pacific/Middle East		**69.45**	39.02	61.32
Total operations		**65.59**	36.75	58.57
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**30.63**	12.13	16.83
United States		**30.63**	12.13	16.85
Canada		**31.18**	5.41	19.87
Europe		**43.97**	23.27	29.37
Asia Pacific		**-**	33.21	37.85
Total international		**37.50**	20.25	32.29
Total consolidated operations		**31.04**	12.90	18.73
Equity affiliates—Asia Pacific/Middle East		**54.16**	32.69	36.70
Total operations		**32.45**	14.61	20.09
Bitumen Per Barrel				
Consolidated operations—Canada	$	**37.52**	8.02 **	31.72
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**2.81**	2.91	3.19
Lower 48		**4.38**	1.65	2.12
United States		**4.38**	1.66	2.12
Canada		**2.54**	1.21	0.49
Europe		**13.75**	3.23	4.92
Asia Pacific*		**6.56**	5.27	5.73
Africa		**3.73**	3.71	4.87
Total international		**8.91**	4.31	5.35
Total consolidated operations		**6.00**	3.13	4.19
Equity affiliates—Asia Pacific/Middle East		**5.31**	3.71	6.29
Total operations		**5.77**	3.38	4.99

**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.*

		2021	2020	2019
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**14.92**	14.60	15.52
Lower 48		**8.48**	9.93	9.59
United States		**9.78**	11.51	11.52
Canada		**15.10**	14.29	16.53
Europe		**9.88**	8.97	11.22
Asia Pacific		**10.21**	9.26	8.74
Africa		**2.95**	6.38	4.46
Total international		**10.53**	10.11	10.26
Total consolidated operations		**9.99**	10.99	10.99
Equity affiliates—Asia Pacific/Middle East		**4.60**	4.01	4.68
Average Production Costs Per Barrel—Bitumen				
Consolidated operations—Canada	$	**13.41**	12.45	13.74
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**6.15**	4.08	3.87
Lower 48		**3.29**	1.87	2.65
United States		**3.87**	2.62	3.05
Canada		**0.67**	0.62	0.78
Europe		**0.73**	0.65	0.48
Asia Pacific		**1.99**	0.81	0.76
Africa		**0.07**	0.91	0.19
Total international		**1.06**	0.72	0.60
Total consolidated operations		**3.06**	1.91	2.03
Equity affiliates—Asia Pacific/Middle East		**11.52**	6.96	11.46
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**12.02**	11.59	8.80
Lower 48		**14.24**	18.05	17.03
United States		**13.79**	15.86	14.35
Canada		**11.16**	13.08	10.00
Europe		**17.13**	16.24	12.75
Asia Pacific		**17.25**	15.66	16.55
Africa		**2.40**	2.43	2.36
Total international		**14.25**	15.01	12.99
Total consolidated operations		**13.92**	15.54	13.78
Equity affiliates—Asia Pacific/Middle East		**8.29**	7.89	8.09

**Includes bitumen.*

Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2021, 2020 and 2019. A "development well" is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "exploratory well" is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and CBM test wells located in Asia Pacific/Middle East.

Net Wells Completed

	Productive			Dry		
	2021	2020	2019	**2021**	2020	2019
Exploratory						
Consolidated operations						
Alaska	**-**	-	7	**1**	3	-
Lower 48	**87**	3	35	**-**	-	6
United States	**87**	3	42	**1**	3	6
Canada	**12**	23	-	**-**	-	-
Europe	**-**	-	1	**-**	*	1
Asia Pacific/Middle East	*****	*	1	*****	*	1
Africa	**-**	-	-	**-**	*	-
Other areas	**-**	-	-	**-**	*	-
Total consolidated operations	**99**	26	44	**1**	3	8
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 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, 2021.

Wells at December 31, 2021

			Productive			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	2	1	1,602	940	-	-
Lower 48	665	337	16,306	8,015	5,091	2,211
United States	667	338	17,908	8,955	5,091	2,211
Canada	18	15	186	94	149	149
Europe	11	1	494	84	59	2
Asia Pacific/Middle East	15	7	351	166	38	18
Africa	7	1	858	140	10	2
Other areas	-	-	-	-	-	-
Total consolidated operations	718	362	19,797	9,439	5,347	2,382
Equity affiliates						
Asia Pacific/Middle East	130	25	-	-	4,908	1,171
Total equity affiliates	130	25	-	-	4,908	1,171

Acreage at December 31, 2021

	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	663	479	1,341	1,329
Lower 48	4,096	2,538	10,514	8,233
United States	4,759	3,017	11,855	9,562
Canada	297	219	3,433	1,948
Europe	430	50	938	371
Asia Pacific/Middle East	921	421	10,451	6,930
Africa	358	58	12,545	2,049
Other areas	-	-	156	125
Total consolidated operations	6,765	3,765	39,378	20,985
Equity affiliates				
Asia Pacific/Middle East	1,039	248	3,807	856
Total equity affiliates	1,039	248	3,807	856

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
2021									
Consolidated operations									
Unproved property acquisition	$ 1	11,261	11,262	4	-	-	-	-	11,266
Proved property acquisition	-	16,101	16,101	1	-	-	-	-	16,102
	1	27,362	27,363	5	-	-	-	-	27,368
Exploration	84	765	849	80	31	51	2	40	1,053
Development	949	2,461	3,410	175	398	433	24	-	4,440
	$ 1,034	30,588	31,622	260	429	484	26	40	32,861
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	-	-	-	-
Proved property acquisition			-						-
	-	-	-	-	-	-	-	-	-
Exploration	-	-	-	-	-	5	-	-	5
Development	-	-	-	-	-	21	-	-	21
	$ -	-	-	-	-	26	-	-	26
2020									
Consolidated operations									
Unproved property acquisition	$ 4	10	14	378	-	3	-	9	404
Proved property acquisition	-	62	62	129	-	-	-	-	191
	4	72	76	507	-	3	-	9	595
Exploration	287	116	403	218	110	32	4	38	805
Development	745	1,758	2,503	102	451	427	18	-	3,501
	$ 1,036	1,946	2,982	827	561	462	22	47	4,901
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	-	-	-	-
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Exploration	-	-	-	-	-	12	-	-	12
Development	-	-	-	-	-	282	-	-	282
	$ -	-	-	-	-	294	-	-	294
2019									
Consolidated operations									
Unproved property acquisition	$ 101	45	146	14	-	-	-	197	357
Proved property acquisition	1	116	117	-	-	115	-	-	232
	102	161	263	14	-	115	-	197	589
Exploration	281	390	671	200	119	66	8	39	1,103
Development	1,125	3,028	4,153	215	625	486	22	-	5,501
	$ 1,508	3,579	5,087	429	744	667	30	236	7,193
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	62	-	-	62
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	62	-	-	62
Exploration	-	-	-	-	-	23	-	-	23
Development	-	-	-	-	-	171	-	-	171
	$ -	-	-	-	-	256	-	-	256

Capitalized Costs

At December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2021									
Consolidated operations									
Proved property	$ 22,750	58,561	81,311	7,380	14,514	12,226	966	-	116,397
Unproved property	1,402	7,704	9,106	1,517	155	92	114	9	10,993
	24,152	66,265	90,417	8,897	14,669	12,318	1,080	9	127,390
Accumulated depreciation, depletion and amortization	11,945	29,975	41,920	2,749	10,166	9,240	422	9	64,506
	$ 12,207	36,290	48,497	6,148	4,503	3,078	658	-	62,884
Equity affiliates									
Proved property	$ -	-	-	-	-	10,357	-	-	10,357
Unproved property	-	-	-	-	-	2,162	-	-	2,162
	-	-	-	-	-	12,519	-	-	12,519
Accumulated depreciation, depletion and amortization	-	-	-	-	-	8,539	-	-	8,539
	$ -	-	-	-	-	3,980	-	-	3,980
2020									
Consolidated operations									
Proved property	$ 21,819	37,452	59,271	7,255	14,931	11,913	942	-	94,312
Unproved property	1,398	631	2,029	1,529	151	89	114	229	4,141
	23,217	38,083	61,300	8,784	15,082	12,002	1,056	229	98,453
Accumulated depreciation, depletion and amortization	11,098	27,948	39,046	2,431	10,015	8,567	387	9	60,455
	$ 12,119	10,135	22,254	6,353	5,067	3,435	669	220	37,998
Equity affiliates									
Proved property	$ -	-	-	-	-	10,310	-	-	10,310
Unproved property	-	-	-	-	-	2,187	-	-	2,187
	-	-	-	-	-	12,497	-	-	12,497
Accumulated depreciation, depletion and amortization	-	-	-	-	-	6,959	-	-	6,959
	$ -	-	-	-	-	5,538	-	-	5,538

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
2021								
Consolidated operations								
Future cash inflows	$ 65,910	125,197	191,107	10,847	21,670	11,583	15,778	250,985
Less:								
Future production costs	34,444	43,034	77,478	4,960	6,090	4,987	801	94,316
Future development costs	8,033	13,386	21,419	923	3,960	1,314	413	28,029
Future income tax provisions	5,310	13,167	18,477	117	8,345	1,542	13,506	41,987
Future net cash flows	18,123	55,610	73,733	4,847	3,275	3,740	1,058	86,653
10 percent annual discount	7,963	22,290	30,253	1,639	696	930	440	33,958
Discounted future net cash flows	$ 10,160	33,320	43,480	3,208	2,579	2,810	618	52,695
Equity affiliates								
Future cash inflows	$ -	-	-	-	-	27,851	-	27,851
Less:								
Future production costs	-	-	-	-	-	15,491	-	15,491
Future development costs	-	-	-	-	-	1,649	-	1,649
Future income tax provisions	-	-	-	-	-	3,071	-	3,071
Future net cash flows	-	-	-	-	-	7,640	-	7,640
10 percent annual discount	-	-	-	-	-	2,640	-	2,640
Discounted future net cash flows	$ -	-	-	-	-	5,000	-	5,000
Total company								
Discounted future net cash flows	$ 10,160	33,320	43,480	3,208	2,579	7,810	618	57,695

	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada*	Europe	Asia Pacific/ Middle East	Africa	Total
2020								
Consolidated operations								
Future cash inflows	$ 30,145	31,533	61,678	4,198	9,857	7,940	9,997	93,670
Less:								
Future production costs	22,905	17,582	40,487	4,316	4,770	3,838	1,277	54,688
Future development costs	7,932	12,799	20,731	750	3,688	1,289	461	26,919
Future income tax provisions	-	376	376	-	267	1,075	7,571	9,289
Future net cash flows	(692)	776	84	(868)	1,132	1,738	688	2,774
10 percent annual discount	(1,501)	(820)	(2,321)	(396)	117	406	294	(1,900)
Discounted future net cash flows	$ 809	1,596	2,405	(472)	1,015	1,332	394	4,674
Equity affiliates								
Future cash inflows	$ -	-	-	-	-	17,284	-	17,284
Less:								
Future production costs	-	-	-	-	-	10,239	-	10,239
Future development costs	-	-	-	-	-	1,186	-	1,186
Future income tax provisions	-	-	-	-	-	1,728	-	1,728
Future net cash flows	-	-	-	-	-	4,131	-	4,131
10 percent annual discount	-	-	-	-	-	1,269	-	1,269
Discounted future net cash flows	$ -	-	-	-	-	2,862	-	2,862
Total company								
Discounted future net cash flows	$ 809	1,596	2,405	(472)	1,015	4,194	394	7,536

**Undiscounted future net cash flows related to the proved oil and gas reserves disclosed for Canada for the year ending December 31, 2020, are negative due to the inclusion of asset retirement costs and certain indirect costs in the calculation of the standardized measure of discounted future net cash flows. These costs are not required to be included in the economic limit test for proved developed reserves as defined in Regulation S-X Rule 4-10. Future net cash flows for Canada were also impacted by lower 12-month average pricing for bitumen 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	Africa	Total
2019								
Consolidated operations								
Future cash inflows	$ 70,341	53,400	123,741	8,244	16,919	13,084	15,582	177,570
Less:								
Future production costs	40,464	22,194	62,658	4,525	5,843	5,162	1,314	79,502
Future development costs	9,721	14,083	23,804	577	4,143	2,179	484	31,187
Future income tax provisions	3,904	2,793	6,697	-	4,201	1,931	12,747	25,576
Future net cash flows	16,252	14,330	30,582	3,142	2,732	3,812	1,037	41,305
10 percent annual discount	6,571	4,311	10,882	1,198	558	835	460	13,933
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	2,977	577	27,372
Equity affiliates								
Future cash inflows	$ -	-	-	-	-	31,671	-	31,671
Less:								
Future production costs	-	-	-	-	-	16,157	-	16,157
Future development costs	-	-	-	-	-	1,218	-	1,218
Future income tax provisions	-	-	-	-	-	3,086	-	3,086
Future net cash flows	-	-	-	-	-	11,210	-	11,210
10 percent annual discount	-	-	-	-	-	4,040	-	4,040
Discounted future net cash flows	$ -	-	-	-	-	7,170	-	7,170
Total company								
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	10,147	577	34,542

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2021	2020	2019	**2021**	2020	2019	**2021**	2020	2019
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	43,363
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)	(15,097)
Net change in prices and production costs	**50,956**	(34,307)	(13,538)	**3,822**	(4,769)	(422)	**54,778**	(39,076)	(13,960)
Extensions, discoveries and improved recovery, less estimated future costs	**10,420**	887	2,985	**(44)**	22	260	**10,376**	909	3,245
Development costs for the year	**4,396**	3,593	5,333	**91**	192	239	**4,487**	3,785	5,572
Changes in estimated future development costs	**(33)**	754	559	**(104)**	(205)	(21)	**(137)**	549	538
Purchases of reserves in place, less estimated future costs	**17,833**	1	10	**-**	(3)	-	**17,833**	(2)	10
Sales of reserves in place, less estimated future costs	**(468)**	(302)	(1,997)	**-**	-	-	**(468)**	(302)	(1,997)
Revisions of previous quantity estimates	**2,985**	(2,299)	2,099	**178**	(42)	69	**3,163**	(2,341)	2,168
Accretion of discount	**964**	3,984	5,144	**344**	804	869	**1,308**	4,788	6,013
Net change in income taxes	**(19,032)**	10,189	4,767	**(760)**	590	(80)	**(19,792)**	10,779	4,687
Total changes	**48,021**	(22,698)	(8,062)	**2,138**	(4,308)	(759)	**50,159**	(27,006)	(8,821)
Discounted future net cash flows at year end	$ **52,695**	4,674	27,372	**5,000**	2,862	7,170	**57,695**	7,536	34,542

- 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.

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, 2021, 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, 2021.

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 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 Governance

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 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2022, 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 2022 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 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 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 181 through 185, are filed as part of this annual report.

ConocoPhillips

Index to Exhibits

Exhibit No.	Description	Incorporated by Reference Exhibit	Form	File No.
2.1	Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012.	2.1	8-K	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.	2.1	10-Q	001-32395
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	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.	2.1	8-K	001-32395
3.1	Amended and Restated Certificate of Incorporation.	3.1	10-Q	001-32395
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips.	3.2	8-K	000-49987
3.3	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015.	3.1	8-K	001-32395
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	001-32395
10.1	1986 Stock Plan of Phillips Petroleum Company.	10.11	10-K	004-49987
10.2	1990 Stock Plan of Phillips Petroleum Company.	10.12	10-K	004-49987
10.5	Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012.	10.14	10-Q	001-32395
10.7	Omnibus Securities Plan of Phillips Petroleum Company.	10.19	10-K	004-49987
10.10.1	Amended and Restated ConocoPhillips Key Employee Supplemental Retirement Plan, dated January 1, 2020.	10.10.1	10-K	001-32395
10.10.2	Eighth Amendment to Retirement Plans as amended and restated effective January 1, 2016.	10.1	10-Q	001-32395

10.11.1	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated January 1, 2020.	10.11.1	10-K	001-32395
10.11.2	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated January 1, 2020.	10.11.2	10-K	001-32395
10.12	2002 Omnibus Securities Plan of Phillips Petroleum Company.	10.26	10-K	000-49987
10.15	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips.	10.17	10-K	001-32395
10.16.1	Rabbi Trust Agreement dated December 17, 1999.	10.11	10-K	001-14521
10.16.2	Amendment to Rabbi Trust Agreement dated February 25, 2002.	10.39.1	10-K	000-49987
10.16.3	Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998.	10.17.3	10-K	001-32395
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	001-32395
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	001-32395
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	001-32395
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	001-32395
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	001-32395
10.17.1	ConocoPhillips Directors' Charitable Gift Program.	10.40	10-K	000-49987
10.17.2	First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program.	10	10-Q	001-32395
10.19.1	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated January 1, 2020.	10.19.1	10-K	001-32395
10.19.2	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated January 1, 2020.	10.19.2	10-K	001-32395
10.20	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014.	10.21	10-K	001-32395
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	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.	10.26	10-K	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.	10.27	10-K	001-32395
10.23	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007.	10.30	10-K	001-32395

10.24	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	001-32395
10.25.1	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	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.	10	10-Q	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.	10.26.6	10-K	001-32395
10.25.7	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013.	10.26.9	10-K	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.	10.2	10-Q	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.	10.1	10-Q	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.	10.26.12	10-K	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.	10.3	10-Q	001-32395
10.25.14	Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014.	10.5	10-Q	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.	10.11	10-Q	001-32395
10.25.18	Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018.	10.26.24	10-K	001-32395
10.26.1	2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.1	8-K	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.	10.3	10-Q	001-32395
10.26.7	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017.	10.1	10-Q	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.	10.27.12	10-K	001-32395
10.26.13	Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018.	10.27.14	10-K	001-32395
10.26.14	Form of Retention Award Terms and Conditions, 2017 revision, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.27.15	10-K	001-32395
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	001-32395
10.27	Amended and Restated 409A Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated January 1, 2020.	10.27	10-K	001-32395
10.29	Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012.	10.9	10-Q	001-32395
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	001-32395
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	001-32395
10.31	Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.1	8-K	001-32395
10.32	Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.2	8-K	001-32395
10.33	Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.3	8-K	001-32395
10.34	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012.	10.4	8-K	001-32395
10.36	ConocoPhillips Clawback Policy dated October 3, 2012.	10.3	10-Q	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.	10.1	8-K	001-32395
10.38	Company Retirement Contribution Make-Up Plan of ConocoPhillips, dated December 28, 2018.	10.39	10-K	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.	10.1	10-Q	001-32395
10.41	ConocoPhillips Executive Restricted Stock Unit Program, dated February 11, 2020.	10.1	10-Q	001-32395

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	001-32395
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	001-32395
10.44	Compensation Resolutions regarding Matthew J. Fox, dated April 8, 2021.	10.1	10-Q	001-32395
10.45	Form of Aircraft Time Sharing Agreement by and between certain executives and ConocoPhillips dated June 21, 2021.	10.2	10-Q	001-32395
10.46	Purchase and Sale Agreement, dated as of September 20, 2021, by and between Shell Enterprises LLC and ConocoPhillips.	10.1	10-Q	001-32395
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. 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.

Signature

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 17, 2022

/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 17, 2022, 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/ 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