**2020**

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# Form 10-K

(Mark One)

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

For the fiscal year ended **December 31, 2020**

OR

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

For the transition period from ________ to ________

Commission file number: **001-32395**

# ConocoPhillips

*(Exact name of registrant as specified in its charter)*

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

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

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

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

| Title of each class | Trading symbols | Name of each exchange on which 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, 2020, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $42.02, was $45.1 billion.

The registrant had 1,354,734,727 shares of common stock outstanding at January 31, 2021.

**Documents incorporated by reference:**

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2021 (Part III)

**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**

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

**Accounting**

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

**Miscellaneous**

| | |
|---|---|
| EPA | Environmental Protection Agency |
| ESG | Environmental, Social and Corporate 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 |

## PART I

Unless otherwise indicated, “the company,” “we,” “our,” “us” and “ConocoPhillips” are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995. The words “anticipate,” “estimate,” “believe,” “budget,” “continue,” “could,” “intend,” “may,” “plan,” “potential,” “predict,” “seek,” “should,” “will,” “would,” “expect,” “objective,” “projection,” “forecast,” “goal,” “guidance,” “outlook,” “effort,” “target” and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company’s disclosures under the headings “Risk Factors” beginning on page 23 and “CAUTIONARY STATEMENT FOR THE PURPOSES OF THE ‘SAFE HARBOR’ PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995,” beginning on page 75.

## Items 1 and 2. BUSINESS AND PROPERTIES

### CORPORATE STRUCTURE

ConocoPhillips is an independent E&P company headquartered in Houston, Texas with operations and activities in 15 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe, and Asia; LNG developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. On December 31, 2020, we employed approximately 9,700 people worldwide and had total assets of $63 billion.

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

On January 15, 2021, we completed the acquisition of Concho Resources Inc. (Concho), an independent oil and gas exploration and production company with operations in New Mexico and West Texas focused on the Permian Basin. For additional information related to this transaction, see Note 25—Acquisition of Concho Resources Inc., in the Notes to Consolidated Financial Statements.

### SEGMENT AND GEOGRAPHIC INFORMATION

We manage our operations through six operating segments, defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. Effective with the third quarter of 2020, we restructured our segments to align with changes to our internal organization. The Middle East business was realigned from the Asia Pacific and Middle East segment to the Europe and North Africa segment. The segments have been renamed the Asia Pacific segment and the Europe, Middle East and North Africa segment. We have revised segment information disclosures and segment performance metrics presented within our results of operations for the current and prior years. For operating segment and geographic information, see Note 24—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwide basis. At December 31, 2020, our operations were producing in the U.S., Norway, Canada, Australia, Indonesia, Malaysia, Libya, China and Qatar.

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

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

The following table is a summary of the proved reserves information included in the “Oil and Gas Operations” disclosures following the Notes to Consolidated Financial Statements. Approximately 80 percent of our proved reserves are in countries that belong to the Organization for Economic Cooperation and 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** | **2020** | 2019 | 2018 |
| Crude oil | | | |
| Consolidated operations | **2,051** | 2,562 | 2,533 |
| Equity affiliates | **68** | 73 | 78 |
| Total Crude Oil | **2,119** | 2,635 | 2,611 |
| Natural gas liquids | | | |
| Consolidated operations | **340** | 361 | 349 |
| Equity affiliates | **36** | 39 | 42 |
| Total Natural Gas Liquids | **376** | 400 | 391 |
| Natural gas | | | |
| Consolidated operations | **1,011** | 1,209 | 1,265 |
| Equity affiliates | **621** | 736 | 760 |
| Total Natural Gas | **1,632** | 1,945 | 2,025 |
| Bitumen | | | |
| Consolidated operations | **332** | 282 | 236 |
| Total Bitumen | **332** | 282 | 236 |
| Total consolidated operations | **3,734** | 4,414 | 4,383 |
| Total equity affiliates | **725** | 848 | 880 |
| Total company | **4,459** | 5,262 | 5,263 |

Total production, including Libya, of 1,127 MBOED decreased 221 MBOED or 16 percent in 2020 compared with 2019, primarily due to:

- Normal field decline.
- The divestiture of our U.K. assets in the third quarter of 2019 and our Australia-West assets in the second quarter of 2020.
- Production curtailments of approximately 80 MBOED, primarily from North American operated assets and Malaysia.
- Lower production in Libya due to the forced shutdown of the Es Sider export terminal and other eastern export terminals after a period of civil unrest.

The decrease in production during 2020 was partly offset by:

- New wells online in the Lower 48, Canada, Norway, Alaska and China.

Production excluding Libya for 2020 was 1,118 MBOED. Adjusting for estimated curtailments of approximately 80 MBOED; closed acquisitions and dispositions; and excluding Libya, production for 2020 would have been 1,176 MBOED, a decrease of 15 MBOED compared with 2019 production. This decrease was primarily due to normal field decline, partly offset by new wells online in the Lower 48, Canada, Norway, Alaska and China. Production from Libya averaged 9 MBOED as it was in force majeure during a significant portion of the year.

Our worldwide annual average realized price decreased 34 percent from $48.78 per BOE in 2019 to $32.15 per BOE in 2020 primarily due to lower realized crude oil, natural gas and bitumen prices. Our worldwide annual average crude oil price decreased 35 percent, from $60.99 per barrel in 2019 to $39.54 per barrel in 2020. Our worldwide annual average natural gas price decreased 32 percent, from $5.03 per MCF in 2019 to $3.41 per MCF in 2020. Average annual bitumen prices decreased 75 percent, from $31.72 per barrel in 2019 to $8.02 per barrel in 2020.

## 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 2020. Alaska operations contributed 28 percent of our consolidated liquids production and 1 percent of our consolidated natural gas production.

| | | | 2020 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| Greater Prudhoe Area | 36.1 % | Hilcorp | 68 | 16 | 4 | 84 |
| Greater Kuparuk Area | 89.2-94.7 | ConocoPhillips | 74 | - | 2 | 74 |
| Western North Slope | 100.0 | ConocoPhillips | 39 | - | 4 | 40 |
| Total Alaska | | | 181 | 16 | 10 | 198 |

*Greater Prudhoe Area*

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska's North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas plant which processes natural gas to recover

NGLs before reinjection into the reservoir. Prudhoe Bay's satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven, Lisburne and North Prudhoe Bay State fields are part of the Greater Point McIntyre Area.

In 2020, development activity included both rotary and coiled-tubing drilling through April, resulting in ten wells drilled and brought online. In response to the oil price collapse, the second half of 2020 saw a reduction in rig activity. Average net production increased from 81 MBOED in 2019 to 84 MBOED in 2020.

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

We operated both a rotary and a coiled-tubing drilling rig in the first half of 2020, resulting in seven operated wells drilled and brought online in 2020. In response to the oil price collapse, the second half of 2020 saw a reduction in rig activity. Average net production decreased from 86 MBOED in 2019 to 74 MBOED in 2020.

*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. In 2020, an extended-reach drilling rig was delivered to the Alpine CD2 drillsite. This rig is North America's largest mobile land rig and is expected to commence drilling operations in 2021.

The Greater Mooses Tooth Unit is the first unit established entirely within the NPR-A. In 2017, we began construction in the unit with two drill sites; Greater Mooses Tooth #1 (GMT-1) and Greater Mooses Tooth #2 (GMT-2). GMT-1 achieved first oil in 2018 and completed drilling in 2019. In 2020, the second of three construction seasons for GMT-2 was completed and drilling operations are expected to commence in 2021 with first oil later in the year.

We operated both a rotary and a coiled-tubing drilling rig in the Western North Slope during 2020, resulting in five operated wells drilled and brought online. In response to the oil price collapse, the second half of 2020 saw a reduction in rig activity. Average net production decreased from 51 MBOED in 2019 to 40 MBOED in 2020.

*Production Curtailments*
In response to the oil price collapse that began in early 2020, we curtailed operated production—in the Greater Kuparuk Area and Western North Slope—by 8 MBOED in 2020. For more information related to the 2020 industry downturn and our response, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

*Alaska North Slope Gas*
In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation, completed preliminary FEED technical work for a potential LNG project which would liquefy and export natural gas from Alaska's North Slope and deliver it to market. In 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment, however, AGDC decided to continue on its own, focusing primarily on permitting efforts. Currently, AGDC is in the process of seeking new sponsors for the project. Given current market conditions, we no longer believe the project will advance and since there is no current market, we recorded a before-tax impairment of $841 million for the entire associated carrying value of capitalized undeveloped leasehold costs and an equity method investment related to our Alaska North Slope Gas asset. We remain willing to sell our Alaska North Slope Gas to interested parties on a competitive basis if a market materializes in the future. For additional information related to this impairment, See Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.

*Exploration*
Appraisal of the Willow Discovery in the Bear Tooth Unit in the National Petroleum Reserve-Alaska (NPR-A) continued with the drilling of two of four planned appraisal wells before the early cancellation of the 2020 program as part of our COVID-19 response. The reduced 2020 appraisal program consisted of drilling a horizontal well in the eastern portion of the field, informing the reservoir's connectivity, and a vertical well in the field's southern extent, reducing the original oil in place uncertainty. The initial development plan for the Willow Discovery, approved in the fourth quarter, does not include the Cassin Discovery from 2013; therefore, we recognized dry hole expense for two previously suspended Cassin wells in 2020.

In 2020, exploration of the Harpoon Complex—Harpoon, Lower Harpoon and West Harpoon—commenced. One exploration well of a planned three-well program was drilled before the early cancellation of our 2020 winter drilling season in response to COVID-19. The well was expensed as a dry hole after evaluations confirmed the well intersected sub-commercial volumes of hydrocarbons in the upper Harpoon interval which will not be developed. Future exploration plans include returning to the Harpoon Complex to explore the remaining potential.

In late 2018, we commenced appraisal of the Putu Discovery with a long-reach well from existing Alpine CD4 infrastructure. In 2019 and 2020 the long reach CD4 appraisal and supporting injector well finished drilling and testing. Production and injectivity tests confirmed development and waterflood feasibility of the reservoir. The project transitioned from appraisal to development in early 2020. Development planning is ongoing.

A 3-D seismic survey was completed in 2020 over a 234-mile area on state and federal lands. We are currently evaluating this seismic data for future exploration opportunities.

*Transportation*
We transport the petroleum liquids produced on the North Slope to Valdez, Alaska through an 800-mile pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.5 percent ownership interest in TAPS, and we also have ownership interests in and operate the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

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

LOWER 48

On January 15, 2021, we completed the acquisition of Concho. This transaction significantly increases our Permian position by adding complementary acreage across the Delaware and Midland basins. The production and acreage figures and the property descriptions below do not reflect this recently closed acquisition. For additional information related to this acquisition, see Note 25—Acquisition of Concho Resources Inc., in the Notes to Consolidated Financial Statements.

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf of Mexico. Organized into the Gulf Coast and Great Plains business units, at year-end 2020 we held 10.1 million net onshore and offshore acres, with a portfolio of low cost of supply, shorter cycle time, resource-rich unconventional plays, and conventional production from legacy assets. Based on 2020 production volumes, the Lower 48 is the company's largest segment and contributed 40 percent of our consolidated liquids production and 44 percent of our consolidated natural gas production.

| | | | 2020 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| Eagle Ford | Various % | Various | 103 | 46 | 228 | 186 |
| Gulf of Mexico | Various | Various | 7 | 1 | 6 | 9 |
| Gulf Coast—Other | Various | Various | 3 | - | 7 | 4 |
| Total Gulf Coast | | | 113 | 47 | 241 | 199 |
| Bakken | Various | Various | 53 | 10 | 92 | 78 |
| Permian Unconventional | Various | Various | 33 | 12 | 113 | 64 |
| Permian Conventional | Various | Various | 12 | 2 | 42 | 21 |
| Anadarko Basin | Various | Various | 1 | 3 | 50 | 13 |
| Wyoming/Uinta | Various | Various | - | - | 44 | 8 |
| Niobrara* | Various | Various | 1 | - | 3 | 2 |
| Total Great Plains | | | 100 | 27 | 344 | 186 |
| Total Lower 48 | | | 213 | 74 | 585 | 385 |

**Disposed in March 2020. See Note 4—Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.*

*Onshore*
At December 31, 2020, we held 10.1 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 1.3 million net acres in the following areas:

- 610,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 200,000 net acres in the Eagle Ford, located in South Texas.
- 170,000 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 300,000 net acres in other areas with unconventional potential.

In response to the oil price collapse that began in early 2020, we curtailed production in the Lower 48 by approximately 55 MBOED in 2020. For more information related to the 2020 industry downturn and our response, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. These production curtailments contributed to lower production in 2020 compared with 2019 from our three focus areas:

- Eagle Ford—We operated five rigs on average in the Eagle Ford during 2020, resulting in 154 operated wells drilled and 71 operated wells brought online. Production decreased 14 percent in 2020 compared with 2019, averaging 186 MBOED and 216 MBOED, respectively.
- Bakken—We operated an average of two rigs during the year in the Bakken and participated in additional development activities operated by co-venturers. We continued our pad drilling with 57 operated wells drilled during the year and 29 operated wells brought online. Production decreased 20 percent in 2020 compared with 2019, averaging 78 MBOED and 97 MBOED, respectively.
- Permian Basin—The Permian Basin is a combination of legacy conventional and unconventional assets. We operated one rig during the full year and another rig during parts of the year in the Permian Basin, resulting in 16 operated wells drilled and 16 operated wells brought online. Production decreased 1 percent in 2020 compared with 2019, averaging 85 MBOED and 86 MBOED, respectively.

*Gulf of Mexico*
At year-end 2020, our portfolio of producing properties in the Gulf of Mexico totaled approximately 60,000 net acres. A majority of the production consists of three fields operated by co-venturers:

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

*Dispositions*
In the first quarter of 2020, we completed the sale of our Waddell Ranch interests in the Permian Basin and our Niobrara interests. Production from these dispositions was immaterial to the Lower 48 segment in 2020. For additional information on these transactions, see Note 4—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

*Facilities*

- Lost Cabin Gas Plant—We operate and own a 60 percent interest in the Lost Cabin Gas Plant, a 246 MMCFD capacity natural gas processing facility in Lysite, Wyoming. The plant is currently operating at less than capacity due to a fire in December 2018. Restoration efforts are ongoing and anticipated to be completed in the first half of 2021. The expected production loss in 2021 is immaterial to the segment.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 110 MBD condensate processing plant located in Kenedy, Texas.
- Sugarloaf Condensate Processing Facility—We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30 MBD condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15 MBD condensate processing plant located in Kenedy, Texas. This facility is currently being decommissioned.

CANADA

Our Canadian operations consist of the Surmont oil sands development in Alberta and the liquids-rich Montney unconventional play in British Columbia. In 2020, operations in Canada contributed 9 percent of our consolidated liquids production and 3 percent of our consolidated natural gas production.

| | | | 2020 | | | | |
|---|---|---|---|---|---|---|---|
| | Interest | Operator | Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Bitumen MBD | Total MBOED |
| **Average Daily Net Production** | | | | | | | |
| Surmont | 50.0 % | ConocoPhillips | - | - | - | 55 | 55 |
| Montney | 100.0 | ConocoPhillips | 6 | 2 | 40 | - | 15 |
| Total Canada | | | 6 | 2 | 40 | 55 | 70 |

*Surmont*
Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called SAGD, whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. We hold approximately 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 Total S.A. that offers long-lived, sustained production. We are focused on structurally lowering costs, reducing GHG intensity and optimizing asset performance.

In response to the oil price collapse that began in early 2020, we voluntarily curtailed production at Surmont by approximately 12 MBOED in 2020. For more information related to the 2020 industry downturn and our response, please see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

*Montney*
In August 2020, we completed the acquisition of additional Montney acreage from Kelt Exploration. This acquisition consisted primarily of undeveloped properties, including 140,000 net acres in the liquids-rich Inga Fireweed asset Montney zone, which is directly adjacent to our existing Montney position. We now hold approximately 300,000 net acres in the Montney play with a 100 percent working interest. For additional information related to the Kelt Exploration acquisition, please see Note 4—Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Following the completion of third-party offtake facilities, our newly commissioned processing facility and production from our 2019 drilling program came online in February 2020. In 2020, development activity consisted of drilling 14 horizontal wells and completing 18 wells. Overall, 23 wells came online in 2020. In 2021, appraisal drilling and completions activity will continue to further explore the area’s resource potential.

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

EUROPE, MIDDLE EAST AND NORTH AFRICA

The Europe, Middle East and North Africa segment consists of operations principally located in the Norwegian sector of the North Sea; the Norwegian Sea; Qatar; Libya; and commercial and terminalling operations in the U.K. In 2020, operations in Europe, Middle East and North Africa contributed 13 percent of our consolidated liquids production and 20 percent of our consolidated natural gas production.

**Norway**

| | | | 2020 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| Greater Ekofisk Area | 30.7-35.1% | ConocoPhillips | 46 | 2 | 39 | 55 |
| Heidrun | 24.0 | Equinor | 12 | 1 | 32 | 18 |
| Aasta Hansteen | 10.0 | Equinor | - | - | 82 | 14 |
| Troll | 1.6 | Equinor | 2 | - | 54 | 11 |
| Alvheim | 20.0 | Aker BP | 8 | - | 13 | 10 |
| Visund | 9.1 | Equinor | 2 | 1 | 40 | 10 |
| Other | Various | Equinor | 8 | - | 10 | 9 |
| Total Norway | | | 78 | 4 | 270 | 127 |

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises four producing fields: Ekofisk, Eldfisk, Embla and Tor. The Tor II redevelopment achieved first production in December 2020. Crude oil is exported to Teesside, England, and the natural gas is 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*
A well we participated in during 2019, Canela, was expensed as a dry hole in 2020 after post drill analysis.

In 2020, we completed the third well of a three-well operated exploration campaign in Block 25/7 in the North Sea with the Hasselbaink Well. The Hasselbaink Well encountered insufficient hydrocarbons and was expensed as a dry hole in 2020. In the second half of 2020 we completed a two-well operated exploration campaign in the Norwegian Sea with the Warka and Slagugle wells. Both the Warka and Slagugle wells encountered hydrocarbons and will be evaluated for future appraisal programs.

We were awarded three new exploration licenses; PL1045, PL1047 and PL1064; and two acreage additions, PL917B and PL1009B. Additionally, we exchanged our interest in the PL938 exploration license for increased interest in the PL1047 exploration license.

*Transportation*
We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude 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 an oil terminal at Teesside, England to support our Norway operations.

**Qatar**

| | | | 2020 | | | |
|---|---|---|---|---|---|---|
| | 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 | 371 | 83 |
| Total Qatar | | | 13 | 8 | 371 | 83 |

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

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

**Libya**

| | Interest | Operator | 2020 Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
|---|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | | |
| Waha Concession | 16.3 % | Waha Oil Co. | 8 | - | 5 | 9 |
| Total Libya | | | 8 | - | 5 | 9 |

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports have periodically been interrupted over the last several years due to the shutdown of the Es Sider crude oil export terminal. In 2020, we had five crude liftings from Es Sider, compared with 19 crude liftings from Es Sider in 2019. Production ceased in February 2020, due to a forced shutdown of the Es Sider export terminal and other eastern export terminals after a period of civil unrest. In October 2020, force majeure was lifted allowing production operations and related oil exports to resume.

ASIA PACIFIC

The Asia Pacific segment has exploration and production operations in China, Indonesia, Malaysia and Australia. In 2020, operations in the Asia Pacific segment contributed 10 percent of our consolidated liquids production and 32 percent of our consolidated natural gas production.

**Australia**

| | Interest | Operator | 2020 Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
|---|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | | |
| Australia Pacific LNG | 37.5% | ConocoPhillips/ Origin Energy | - | - | 684 | 114 |
| Bayu-Undan* | 56.9 | ConocoPhillips | 2 | 1 | 87 | 17 |
| Total Australia and Timor-Leste | | | 2 | 1 | 771 | 131 |

**This asset was disposed in May 2020. See Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.*

*Australia Pacific LNG*

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

We operate two fully subscribed 4.5-million-metric-tonnes-per-year LNG trains. Approximately 2,800 net wells are ultimately expected to supply both the LNG sales contracts and domestic gas market. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities, and an export pipeline connecting the gas fields to the LNG facilities. The LNG is being sold to Sinopec under 20-year sales agreements for 7.6 million metric tonnes of LNG per year, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

As of December 31, 2020, APLNG has an outstanding balance of $6.2 billion on a $8.5 billion project finance facility. Project finance interest payments are bi-annual, concluding September 2030.

For additional information, see Note 5—Investments, Loans and Long-Term Receivables and Note 11—Guarantees, in the Notes to Consolidated Financial Statements.

*Exploration*
In 2019, we entered into an agreement with 3D Oil to acquire a 75 percent interest in and operatorship of an offshore Exploration Permit (T/49P) located in the Otway Basin, Australia. We obtained an additional five percent interest in 2020, increasing our interest to 80 percent. The required government approvals for the transfer of this interest were obtained in June 2020. We plan to conduct a 3-D seismic survey in the second half of 2021, subject to governmental approval of a recently submitted Environmental Plan.

*Dispositions*
In May 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations. These subsidiaries held a 37.5 percent interest in the Barossa Project and Caldita Field, a 56.9 percent interest in the Darwin LNG Facility and Bayu-Undan Field, and a 40 percent interest in the Greater Poseidon Fields. Production from the beginning of the year through the disposition date in May 2020 averaged 43 MBOED. See Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.

**Indonesia**

| | | | 2020 | | | |
|---|---|---|---|---|---|---|
| | Interest | Operator | Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
| **Average Daily Net Production** | | | | | | |
| South Sumatra | 54 % | ConocoPhillips | 2 | - | 290 | 50 |
| Total Indonesia | | | 2 | - | 290 | 50 |

During 2020, we operated two PSCs in Indonesia: the Corridor Block located in South Sumatra, and Kualakurun in Central Kalimantan. Currently, we have production from the Corridor Block.

*South Sumatra*
The Corridor PSC consists of two oil fields and seven producing natural gas fields. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets 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 2-D seismic acquisition program. After completion of prospect evaluation, both PSC contractors decided to relinquish rights and return this block to the government.

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

**China**

| | Interest | Operator | 2020 Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
|---|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | | |
| Penglai | 49.0 % | CNOOC | 30 | - | - | 30 |
| Total China | | | 30 | - | - | 30 |

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

Wellhead Platform J Project in the Penglai 19-9 Field achieved first production in 2016. This project consisted of 62 wells that have all been completed and brought online as of December 2020.

The Phase 3 Project in the Penglai 19-3 and 19-9 fields consists of three new wellhead platforms and a central processing platform. First production from Phase 3 was achieved in 2018 for two wellhead platforms and in 2020 for the third wellhead platform. This project could include up to 186 wells, 91 of which have been completed and brought online as of December 2020.

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

*Panyu*
We have a production license for Panyu 4-1 in Block 15/34. If a development occurs, our production license is for 15 years upon commencement of production.

*Exploration*
Exploration activities in the Bohai Penglai Field during 2020 consisted of two successful appraisal wells supporting future developments in the Bohai Bay Block 11/05.

We fulfilled our exploration well commitment in Panyu 4-1 in early 2020. No further exploration well operations are planned.

**Malaysia**

| | Interest | Operator | 2020 Crude Oil MBD | NGL MBD | Natural Gas MMCFD | Total MBOED |
|---|---|---|---|---|---|---|
| **Average Daily Net Production** | | | | | | |
| Gumusut | 29.0 % | Shell | 21 | - | - | 21 |
| Malikai | 35.0 | Shell | 11 | - | - | 11 |
| Kebabangan (KBB) | 30.0 | KPOC | 1 | - | 52 | 10 |
| Siakap North-Petai | 21.0 | PTTEP | 2 | - | - | 2 |
| Total Malaysia | | | 35 | - | 52 | 44 |

We have varying stages of exploration, development and production activities across 1.5 million net acres in Malaysia, with working interests in five PSCs. Three of these PSCs are located in waters off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). We operate two exploration blocks, Block WL4-00 and SK304 in waters off the eastern Malaysian state of Sarawak.

**Block J**

*Gumusut*

We currently have a 29 percent working interest in the Gumusut Field following the redetermination of the Block J and Block K Malaysia Unit in 2017. Gumusut Phase 2 first oil was achieved in 2019. Development drilling associated with Gumusut Phase 3 is planned to commence in the fourth quarter of 2021 with the first of four planned wells. First oil is anticipated in 2022.

**KBBC**

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

*KBB*

During 2019, KBB tied-in to a nearby third-party floating LNG vessel which provided increased gas offtake capacity. Production from the field has been reduced since January 2020, due to the rupture of a third-party pipeline which carries gas production from KBB to market. The pipeline operator has initiated repairs with no production expected to flow through the full length of the pipeline during 2021.

**Block G**

*Malikai*

We hold a 35 percent working interest in Malikai. This field achieved first production in December 2016 via the Malikai Tension Leg Platform, ramping to peak production in 2018. The KMU-1 exploration well was completed and started producing through the Malikai platform in 2018. Malikai Phase 2 development, a six-well drilling campaign, commenced in 2020, with first oil anticipated in 2021.

*Siakap North-Petai*

We hold a 21 percent working interest in the unitized Siakap North-Petai (SNP) oil field. First oil from SNP Phase 2, a four-well program, is anticipated in the fourth quarter of 2021.

**Production Curtailments**

We experienced production curtailments of 4 MBOED in 2020.

**Exploration**

In 2017, we were awarded operatorship and a 50 percent working interest in Block WL4-00, which included the existing Salam-1 oil discovery and encompassed 0.6 million gross acres. In 2018 and 2019, two exploration and two appraisal wells were drilled, resulting in oil discoveries under evaluation at Salam and Benum, while two Patawali wells were expensed as dry holes in 2019. Further exploration drilling is planned for 2021.

In 2018, we were awarded a 50 percent working interest and operatorship of Block SK304 encompassing 2.1 million gross acres offshore Sarawak. We acquired 3-D seismic over the acreage and completed processing of this data in 2019. Exploration drilling is planned for 2021.

In June 2020, we relinquished our 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block offshore Sarawak.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia and Argentina and 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. The block extends over approximately 67,000 net acres and contains the Picoplata-1 Well, which completed drilling in 2015 and testing in 2017. Plug and abandonment activity started during 2018 and completed in 2019. In addition, we have an 80 percent working interest in the VMM-2 Block which extends over approximately 58,000 net acres and is contiguous to the VMM-3 Block. As part of a case brought forward by environmental groups, the Highest Administrative Court granted a preliminary injunction temporarily suspending hydraulic fracturing activities until the substance of the case is decided. As a result, we filed two separate Force Majeure requests before the relevant authority for both blocks, which were granted. We have no immediate plans to perform under existing contracts, therefore, the Picoplata-1 Well was recorded to dry hole expense and we fully impaired the capitalized undeveloped leasehold costs associated with our Colombia assets during 2020.

**Chile**
In September 2020, we notified the operator of our decision to exit our 49 percent interest in the Coiron Block, located in the Magallanes Basin in southern Chile. We are working with local authorities to finalize our withdrawal from this block.

**Argentina**
We have a 50 percent nonoperated interest in El Turbio Este Block, within the Austral Basin in southern Argentina. Following the acquisition and processing of 3-D seismic covering approximately 500 square miles in 2019, planned activities in 2020 were delayed due to the impact of COVID-19 and force majeure in the block.

We have a 50 percent non-operated interest in the Bandurria Norte and Aguada Federal blocks within the Neuquen Basin in central Argentina. Following a successful production test of two horizontal wells on the Aguada Federal Block, we increased our interest from 45 to 50 percent in April 2020 where two horizontal wells continued production testing throughout the year. Preparation for a 2021 work program is ongoing.

**Venezuela and Ecuador**
For discussion of our contingencies in Venezuela and Ecuador, see Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

OTHER

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

*Natural Gas*
Our natural gas production, along with third-party purchased gas, is primarily marketed in the U.S., Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

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

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

**Energy Partnerships**
*Marine Well Containment Company (MWCC)*
We are a founding member of the MWCC, a non-profit organization formed in 2010, which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. MWCC's containment system meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico.

*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. Globally, our primary OSRO is Oil Spill Response Ltd. based in the U.K., with facilities in several other countries and the ability to respond anywhere in the world. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental U. S. and Alaska Clean Seas and Ship Escort/Response Ves sel System for the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain memberships in various regional OSROs including the Norwegian Clean Seas Association for Operating Companies, Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

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

We are the second largest LNG liquefaction technology provider globally. Our Optimized Cascade® LNG liquefaction technology has been licensed for use in 27 LNG trains around the world, with feasibility studies ongoing for additional trains and four new products announced in 2020 that expand the scope of LNG licensing.

## RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2020. No difference exists between our estimated total proved reserves for year-end 2019 and year-end 2018, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2020.

## DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 1.1 trillion cubic feet of natural gas and 156 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 “Oil and Gas Operations” section following the Notes to Consolidated Financial Statements, for information on the development of PUDs.

## COMPETITION

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

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, NGLs and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 7, 2020, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids production and reserves and one of the top ten U.S. companies measured by worldwide natural gas production and reserves in 2019. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

## HUMAN CAPITAL MANAGEMENT

### Values, Principles and Governance

At ConocoPhillips, our human capital management approach is anchored to our core SPIRIT Values. Our SPIRIT Values – Safety, People, Integrity, Responsibility, Innovation, and Teamwork – set the tone for how we interact with all our stakeholders, internally and externally. In particular, we believe a safe organization 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 human capital management philosophies and tracking our progress. The ELT and Board of Directors engage often on workforce-related topics. Our human capital management programs are overseen and administered by our human resources function with support from business leaders across the company.

We depend on our workforce to successfully execute our company’s strategy and we recognize the importance of creating a workplace in which our people feel valued. We take a broad view of human capital management that begins with offering a compelling culture and includes programs and processes necessary for ensuring we have an engaged workforce with the skills to meet our business needs. The key elements of our human capital management are described below.

### COVID-19 Response

In 2020, a significant effort was undertaken to address the ongoing COVID-19 pandemic. In the very early stages of the pandemic, we adopted and embraced three company-wide priorities to guide our activities in the midst of COVID-19: to protect our employees, 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. We transitioned to a remote work environment for periods of time to ensure the safety of our employees, partners and the community, and then implemented rigorous cleaning and disinfecting processes and rigorous mitigation protocols to keep our workforce safe, including temperature scans, social distancing, face covering requirements and increased sanitation as employees returned to the office setting.

**Culture of Feedback and Engagement**

Our human capital management approach recognizes that a compelling culture and an engaged workforce are powerful determinants of business success. Beginning in 2019, we launched a coordinated, multi-year, global employee feedback program called "Perspectives." In mid-2019 we administered our first Perspectives survey, which received an 86 percent employee response rate and yielded more than 35,000 comments. We achieved an employee satisfaction score that, on a 100-point scale, was 5 points higher than general industry and 11 points higher than our energy peers who used the same platform. Importantly, the quantitative and qualitative survey data were used by leaders across the company to identify and analyze relative strengths and gaps and to develop action plans to address gaps.

We intended to repeat the comprehensive Perspectives survey in 2020; however, in light of the COVID-19 pandemic and the significant industry downturn, we elected to defer the full survey until 2021 and instead focused our 2020 feedback program on the specific topic of Diversity and Inclusion (D&I). The survey "Perspectives Pulse: D&I" also received a high response rate with over 10,000 comments. The ELT and an internal D&I Council are responsible for analyzing the survey data to identify D&I strengths and gaps, and to use the findings to establish 2021 D&I priorities and action plans. The company's D&I commitment, activities and programs are described below.

**Diversity and Inclusion**

Our commitment to D&I is foundational to our SPIRIT Values and our stated company-wide D&I goal is to have "a diverse culture of belonging where everyone feels valued." We believe a diverse workforce and an inclusive environment that reflects different backgrounds, experiences, ideas and perspectives drives innovation, employee satisfaction and overall company performance. We hold our entire workforce accountable for creating and sustaining an inclusive work environment. Our leaders are accountable for having personal D&I goals each year and we believe senior leadership involvement is critical for achieving meaningful progress on D&I.

The ELT has ultimate accountability for advancing our D&I commitment through a governance structure that includes an ELT-level D&I Champion, a global D&I Council consisting of senior leaders from across the company and organization-wide D&I goals. Leaders meet regularly with each other and with the workforce to discuss challenges, opportunities, best practices and progress. In addition, our D&I plans and progress are reviewed regularly with the Board of Directors.

In 2018, the company established three pillars to guide our D&I activities: leadership accountability, employee awareness, and processes and programs. Since then, we have established corporate priorities annually under each of these areas. In 2020 we also published our first D&I Annual Report internally and we expect to update this report periodically as an important part of holding ourselves accountable for progressing our D&I goals throughout ConocoPhillips. Some of our key D&I actions and accomplishments over the past few years include:

- Publishing our first D&I Dashboards internally which contain key D&I statistics for our global and U.S. employees at year-end for the periods 2015-2019;
- Launching a company-wide platform for our workforce to talk openly about D&I;
- Expanding our workforce recognition programs to include a prestigious "SPIRIT Award" for D&I advocates;
- Implementing a "how rating" and an upward feedback process as part of our performance management system to hold our workforce and our leaders accountable for D&I;
- Broadening our D&I-related training resources; and
- Advocating for broad participation in, and awareness of our extensive network of employee resource groups, which drew participation from over 5,000 people in 2020.

We recognize that achieving our D&I goals require the visible actions described above, but also requires a clear linkage to the daily activities of our workforce. These activities include:

- Educating managers on inclusive hiring practices;
- Conducting immersive D&I training for senior leaders and influencers;
- Examining our Talent Management Teams' processes to eradicate bias within our selection and succession efforts;
- Working with partners to connect veterans and individuals with disabilities with employment;
- Promoting inclusion of employees with disabilities through a robust accommodation process available to all employees;
- Ensuring diverse internal and external candidate slates; and
- Creating balanced interview teams to mitigate any unconscious bias in our hiring processes.

We actively monitor diversity metrics on a global basis. In addition to our internal dashboards, we publicly report our representation of women and minorities in leadership roles. We have also committed to publicly disclose ConocoPhillips' Consolidated EEO-1 Report effective upon our next submission to the U.S. Equal Employment Opportunity Commission in 2021. Tables of 2020 employee demographics by gender and ethnicity, and by country, are shown below:

**2020 Employees by Gender* and Ethnicity**

| | Male | Female | Non-POC** | POC |
|---|---|---|---|---|
| All Employees | 73 % | 27% | 75 % | 25 % |
| All Leadership | 77 | 23 | 81 | 19 |
| Top Leadership | 81 | 19 | 87 | 13 |
| Junior Leadership | 76 | 24 | 78 | 22 |

**While we present male and female, we acknowledge this is not fully encompassing of all gender identities.*
***"POC" refers to People of Color or racial and ethnic minorities self-reported in the U.S.*
*Note: percentages based on year-end 2020 employee count of 9,700.*

| 2020 Employees by Country | Percent of Total |
|---|---|
| USA | 59 % |
| Norway | 19 |
| Canada | 8 |
| Indonesia | 6 |
| Great Britain | 3 |
| Australia | 3 |
| China | 1 |
| Other Global Locations | 1 |
| | 100 |

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

**Hiring & Retention**

Our success depends on having the right workforce to meet our business needs. Attracting and retaining a skilled, engaged and diverse workforce is a top priority. We conduct routine personnel needs assessments with leaders to ensure we have the organizational capacity and capabilities to execute our business plans. We've taken significant steps to embed inclusion into each step of our recruiting practices, including adapting the way we construct job descriptions to using intentionally diverse interview panels.  To attract qualified, diverse candidates for full-time positions or internships, we recruit from a number of universities in the U.S.  By attending conferences and recruiting at Hispanic-serving institutions and historically black colleges and universities, we have extended a broader outreach to potential diverse candidates.

We closely monitor recruitment metrics through our university dashboards in areas such as gender, ethnicity and university acceptance rates to help guide decisions and best practices.  These are disclosed internally through our D&I Dashboards to ensure greater transparency.  In addition, voluntary turnover metrics are routinely tracked and disclosed to guide our retention activities, as necessary.

| **2020 Hiring & Retention Metrics (U.S.)** | **Percent of Total** |
|---|---|
| University hire acceptance | 85 % |
| Interns acceptance | 74 |
| Diversity hiring - Women | 29 |
| Diversity hiring - POC | 28 |
| Total voluntary attrition | 3 |

*Talent Development*

We employ a comprehensive approach for ensuring our workforce is adequately prepared for their responsibilities and also to advance their career. Our workforce is trained through a combination of on-the-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 rating to assess behaviors to ensure they are in line with our SPIRIT values.

ConocoPhillips has established core leadership competencies that provide a common baseline of knowledge, skills, abilities, and behaviors to support employee performance, growth, and success.  All supervisors have access to a voluntary 360-feedback tool to receive feedback on their strengths and opportunities relative to these competencies.  We offer training on a broad range of technical and professional skills, from data analytics to communication skills.

*Compensation, Benefits and Well-Being*

We offer competitive, performance-based compensation packages and have global equitable pay practices. Our compensation programs are generally comprised of a base pay rate, the annual Variable Cash Incentive Program (VCIP) and, for eligible employees, the Restricted Stock Unit (RSU) program.  From the CEO to 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 2020, our U.S. parental leave benefit increased from two weeks to six weeks and combined with our maternity benefit (eight weeks), new birth mothers are eligible for up to 14 weeks of paid leave.

Our global wellness programs include biometric screenings and fitness challenges designed to educate and promote a healthy lifestyle. All employees have access to our employee assistance program, and many of our locations offer custom programs to support mental well-being.

*Compensation Risk Mitigation*
ConocoPhillips has considered the risks associated with each of its executive and broad-based 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 utilized under each incentive compensation program. As a result of this review, management concluded the risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on ConocoPhillips. As part of the Board of Directors' oversight of ConocoPhillips' risk management programs, the Human Resources Compensation Committee (HRCC) conducts a similar review with the assistance of its independent compensation consultant. The HRCC agrees with management's conclusion that the risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on ConocoPhillips.

## GENERAL

At the end of 2020, we held a total of 1,038 active patents in 50 countries worldwide, including 419 active U.S. patents. During 2020, we received 65 patents in the U.S. and 69 foreign patents. Our products and processes generated licensing revenues of $16 million related to activity in 2020. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

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

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 64 through 69 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2020 and those expected for 2021 and 2022.

### Website Access to SEC Reports
Our internet website address is *www.conocophillips.com*. Information contained on our internet website is 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

***We have been negatively affected and may continue to be negatively affected by the prolonged drop in commodity prices that began in early 2020.***

The oil and gas business is fundamentally a commodity business and our revenues, operating results and future rate of growth are highly dependent on the prices we receive for crude oil, bitumen, natural gas, NGLs and LNG. Such prices can fluctuate widely depending upon global events or conditions that affect supply and demand, most of which are out of our control. Since early 2020, there has been a precipitous decrease in demand for oil globally, largely caused by the dramatic decrease in travel and commerce resulting from the COVID-19 pandemic. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, for additional information on commodity prices and how we have been impacted. There is no assurance of when or if commodity prices will return to pre-COVID-19 levels, and if they do return to pre-COVID levels, how long they will remain at those levels. The speed and extent of any recovery remains uncertain and is subject to various risk factors, including the duration, impact and actions taken to stem the proliferation of the COVID-19 pandemic, the extent to which those nations party to the OPEC plus production agreement decide to increase production of crude oil, bitumen, natural gas and NGLs and other factors described herein. Even after a recovery, our industry will continue to be exposed to the effects of changing commodity prices given the volatility in commodity price drivers and the worldwide political and economic environment generally, as well as continued uncertainty caused by armed hostilities in various oil-producing regions around the globe.

Lower crude oil, bitumen, natural gas, NGL and LNG prices may have a material adverse effect on our revenues, earnings, cash flows and liquidity, and may also affect the amount of dividends we elect to declare and pay on our common stock. As a result of the oil market downturn that began in early 2020, we suspended our share repurchase program. Lower prices may also limit the amount of reserves we can produce economically, thus adversely affecting our proved reserves and reserve replacement ratio and accelerating 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, NGLs and LNG prices could also require us to reduce our capital expenditures, impair the carrying value of our assets or discontinue the classification of certain assets as proved reserves. In 2020, we recognized several impairments, which are described in Note 7—Suspended Wells and Exploration Expenses and Note 8—Impairments, in the Notes to Consolidated Financial Statements, due to changes in assumptions for commodity prices and development plans. If the outlook for commodity prices remains low relative to historic levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. If oil and gas prices persist at depressed levels, our reserve estimates may decrease further, which could incrementally increase the rate used to determine DD&A expense on our unit-of-production method properties. See Item 7. Management's Discussion and Analysis for further examination of DD&A rate impacts versus comparative periods. Although it is not reasonably practicable to quantify the impact of any future impairments or estimated change to our unit-of-production rates at this time, our results of operations could 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. According to the National Bureau of Economic Research, as a result of the pandemic and its broad reach across the entire economy, the U.S. entered a recession in early 2020 and the timing, pace and extent of the recovery is still unknown. Public health 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. In addition, despite approval of vaccines to immunize against COVID-19, the speed at which such vaccinations will be available to the public, the public’s willingness to be inoculated and the effectiveness of the vaccine (including to variants) still remain unknown. As a result, the full impact of the COVID-19 pandemic remains uncertain and will depend on the severity, location and duration of the effects and spread of the disease, the effectiveness and duration of actions taken by authorities to contain the virus or treat its effect, the availability and effectiveness of vaccines or other treatments, and how quickly and to what extent economic conditions improve.

We have already been impacted by the COVID-19 pandemic. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, for additional information on how we have been impacted and the steps we have taken in response.

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

- Continued reduced demand for our products as a result of prolonged reductions in travel and commerce, even if restrictions are lifted;
- Disruptions in our supply chain due in part to scrutiny or embargoing of shipments from infected 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;
- Business interruptions resulting from a portion of our workforce continuing to telecommute, as well as the implementation and maintenance of protections for employees commuting for work, such as personnel screenings and self-quarantines before or after travel; and
- Voluntary or involuntary curtailments to support oil prices or alleviate storage shortages for our products.

Any of these factors, or other cascading effects of the COVID-19 pandemic that are not currently 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 add to our existing proved reserves, our future crude oil, bitumen, natural gas and NGL production will decline, resulting in an adverse impact to our business.***

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

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

The exploration and production of crude oil, bitumen, natural gas and NGLs is a highly competitive business. We compete with private, public and state-owned companies in all facets of the exploration and production business, including to locate and obtain new sources of supply and to produce crude oil, bitumen, natural gas and NGLs in an efficient, cost-effective manner. Some of our competitors are larger and have greater resources than we do or may be willing to incur a higher level of risk than we are willing to incur to obtain potential sources of supply. 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 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. Because legal requirements are frequently changed and subject to interpretation, we cannot predict whether future restrictions on our business may be enacted or become applicable to us.

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

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

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

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

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

**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;
- Carbon taxes;
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes;
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives; 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. 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, carbon taxes, restrictive permitting, increased fuel efficiency standards and incentives or mandates for renewable energy. For example, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris that prepared an agreement requiring member countries to review and represent a progression in their intended GHG emission reduction goals every five years beginning in 2020. While the U.S. previously withdrew from the Paris Agreement, the new administration has recommitted the United States to the Paris Agreement, and a significant number of U.S. state and local governments and major corporations headquartered in the U.S. have also announced their intention to satisfy these commitments. In addition, our operations continue in countries around the world which are party to, and have not announced an intent to withdraw from, the Paris Agreement. The implementation of current agreements and regulatory measures, as well as any future agreements or measures addressing climate change and GHG emissions, may adversely impact the demand for our products, impose taxes on our products or operations or require us to purchase emission credits or reduce emission of GHGs from our operations. As a result, we may experience declines in commodity prices or incur substantial capital expenditures and compliance, operating, maintenance and remediation costs, any of which may have an adverse effect on our business and results of operations.

In October 2020, we announced the adoption of a Paris-aligned climate risk framework, whereby we committed to a reduction of our gross operated (scope 1 and 2) emissions intensity, with an ambition to achieve net zero by 2050 from operated emissions. We also endorsed the World Bank Zero Routine Flaring by 2030 initiative, with an ambition to meet that goal by 2025 and reaffirmed our commitment to advocate for reduction of scope 3 emissions intensity through our support for a U.S. carbon price. Compliance with, and achievement of, climate change related internal initiatives such as the foregoing may increase costs, require us to purchase emission credits, or limit or impact our business plans, potentially resulting in the reduction to the economic end-of-field life of certain assets and an impairment of the associated net book value.

Increasing attention to global climate change has also resulted in pressure upon stockholders, financial institutions and/or financial markets to modify their relationships with oil and gas companies and to limit investments and/or funding to such companies. For example, in 2019 Norway's Government Pension Fund announced it would reduce its investment exposure to companies that explore for oil and gas, and in 2020 a number of major financial institutions announced that they would no longer finance oil and gas exploration projects in the Arctic. As public pressure continues to mount, our access to capital on terms we find favorable (if it is available at all) may be limited and our costs may increase or our business and results of operations may be otherwise adversely affected.

Furthermore, increasing attention to global climate change has resulted in an increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely 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.

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

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

Actions of the U.S., state, local and foreign governments, through sanctions, tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the U.S. and abroad. In certain locations, restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries 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. The change in control of Congress and the White House because of the 2020 election increases the possibility of the promulgation of more stringent regulations of our operations and the enactment of tax law changes that may adversely affect the fossil fuel industry. In addition, the current administration may use the Congressional Review Act to repeal the regulations finalized in the last five months of the prior administration. We also cannot rule out the possibility of similar regulatory shifts and attendant cost and market access implications in other international jurisdictions.

One area subject to significant political and regulatory activity is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower 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. On January 27, 2021, the new administration signed an executive order directing the Secretary of the Interior to stop issuing new oil and gas leases on federal lands, allowing time to review and reset the Federal Government's oil and gas leasing program. Existing production and permits already issued on Federal lands were not impacted by this order. If this temporary moratorium were to be extended indefinitely, we believe we can mitigate the impact for a considerable period of time with our current permits and adjusting our development plans across our diverse acreage position.

In addition, certain interest groups have also proposed ballot initiatives and constitutional amendments designed to restrict oil and natural gas development generally and hydraulic fracturing in particular. In the event that ballot initiatives, local, state, or national restrictions or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development or production activities. Such 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 PDVSA or the ICSID Award against the Government of Venezuela; or to obtain or maintain permits, including those necessary for drilling and development of wells in various locations. Similarly, the declaration of a "climate emergency" could result in actions to limit exports of our products and other restrictions.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 48 percent of our hydrocarbon production was derived from production outside the U.S. in 2020, and 42 percent of our proved reserves, as of December 31, 2020, were located outside the U.S. We are subject to risks associated with operations in international markets, including changes in foreign 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. 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.

**Risks Related to Our Acquisition of Concho**

***Combining our business with Concho's may be more difficult, costly or time-consuming than expected and we may fail to realize the anticipated benefits of the Merger, which may adversely affect our business results and negatively affect the value of our common stock.***

Our acquisition of Concho (the Merger) involved the combination of two companies which, until the completion of the Merger, operated as independent public companies. The success of the Merger will depend on, among other things, the ability of our two companies to combine our businesses in a manner that adds value to shareholders. However, there can be no assurances that our respective businesses can be integrated successfully, and we will be required to devote significant management attention and resources to the integration process. We must achieve the anticipated improvement in free cash flow generation and returns and achieve the planned cost savings without adversely affecting current revenues or compromising the disciplined investment philosophy to maximize value for shareholders.

There are a large number of processes, policies, procedures, operations and technologies and systems that must be integrated, and although we expect that the elimination of duplicative costs, strategic benefits, and additional income, as well as the realization of other efficiencies related to the integration of the business, may offset incremental transaction and Merger-related costs over time, we may encounter difficulties in the integration and any net benefit may not be achieved in the near term or at all. It is possible that the integration process could take longer than originally anticipated and could result in the loss of key employees; the loss of commercial and vendor partners; the disruption of our ongoing businesses; inconsistencies in standards, controls, procedures and policies; unexpected integration issues; and higher than expected integration costs.

An inability to realize the full extent of the anticipated benefits of the Merger and the other transactions contemplated by the Merger Agreement, as well as any delays encountered in the integration process, could have an adverse effect upon the revenues, level of expenses and operating results of ConocoPhillips, which may adversely affect the value of our common stock.

***The market value of our common stock could decline if large amounts of our common stock are sold now that the Concho acquisition has been consummated.***

We issued shares of ConocoPhillips common stock to former Concho stockholders. Former Concho stockholders may decide not to hold the shares of ConocoPhillips common stock that they received in the Merger, and ConocoPhillips stockholders may decide to reduce their investment in ConocoPhillips as a result of the changes to ConocoPhillips' investment profile as a result of the Merger. Other Concho stockholders, such as funds with limitations on their permitted holdings of stock in individual issuers, may be required to sell the shares of ConocoPhillips common stock that they received in the Merger. Such sales of ConocoPhillips common stock could have the effect of depressing the market price for ConocoPhillips common stock.

**Other Risk Factors Facing our Business or Operations**

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

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

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

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

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

In particular, in August 2018, we entered into a settlement agreement with Petróleos de Venezuela, S.A. (PDVSA) providing for the payment of approximately $2 billion over a five-year period in connection with an arbitration award issued by the International Chamber of Commerce (ICC) Tribunal in favor of ConocoPhillips on a contractual dispute arising from Venezuela's expropriation of our interests in the Petrozuata and Hamaca heavy oil ventures and other pre-expropriation fiscal measures. We have collected approximately $0.8 billion of the $2.0 billion settlement to date and PDVSA has defaulted on its remaining payment obligations under this agreement. We are therefore incurring additional costs as we seek to recover any unpaid amounts under the agreement. Additionally, in March 2019, an ICSID arbitration tribunal issued an award unanimously ordering the government of Venezuela to pay ConocoPhillips approximately $8.7 billion in compensation for the government's unlawful expropriation of the company's investments in Venezuela in 2007. ConocoPhillips has filed requests for recognition of the award in several jurisdictions. On August 29, 2019, the ICSID tribunal issued a decision rectifying the award and reducing it by approximately $227 million. The award now stands at $8.5 billion plus interest. The government of Venezuela is seeking annulment of the award before another panel at ICSID and annulment proceedings are underway. No amounts have been collected as a result of this award yet.

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

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

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

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

Additionally, as of December 31, 2020, $14.5 billion of repurchase authority remained of the $25 billion 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, and we may do so again in the future.

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

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

We regularly review our portfolio and pursue growth through acquisitions and seek to divest non-core assets 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) difficulties in integrating the operations, technologies, products and personnel of the acquired assets or businesses; (iii) the inability to dispose of non-core assets and businesses on satisfactory terms and conditions; and (iv) the discovery of unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections are inadequate or we lack insurance or indemnities, including environmental liabilities, or with regard to divested assets or businesses, claims by purchasers to whom we have provided contractual indemnification.

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

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

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

Although we have experienced occasional breaches of our cyber security, none of these breaches have had a material effect on our business, operations or reputation. As cyber attacks continue to evolve, we must continually expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities detected. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased costs. Despite our ongoing investments in security resources, talent and business practices, we are unable to assure that any security measures will be effective.

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

## Item 1B. UNRESOLVED STAFF COMMENTS

None.

## Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

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

*Matters Previously Reported—Phillips 66*

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

## Item 4. MINE SAFETY DISCLOSURES

Not applicable.

## INFORMATION ABOUT OUR EXECUTIVE OFFICERS

| Name | Position Held | Age* |
|---|---|---|
| Catherine A. Brooks | Vice President and Controller | 55 |
| William L. Bullock, Jr. | Executive Vice President and Chief Financial Officer | 56 |
| Ellen R. DeSanctis | Senior Vice President, Corporate Relations | 64 |
| Matt J. Fox | Executive Vice President and Chief Operating Officer | 60 |
| Ryan M. Lance | Chairman of the Board of Directors and Chief Executive Officer | 58 |
| Timothy A. Leach | Executive Vice President, Lower 48 | 61 |
| Andrew D. Lundquist | Senior Vice President, Government Affairs | 60 |
| Dominic E. Macklon | Senior Vice President, Strategy, Exploration and Technology | 51 |
| Nicholas G. Olds | Senior Vice President, Global Operations | 51 |
| Kelly B. Rose | Senior Vice President, Legal, General Counsel | 54 |

**On February 16, 2021.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter 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 11, 2021. Set forth below is information about the executive officers.

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

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

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

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

**Ryan M. Lance** was appointed Chairman of the Board of Directors and Chief Executive Officer in May 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 Senior Vice President, Strategy, Exploration and Technology as of August 2020, having previously served as President, Lower 48 since June 2018. Prior to that, he served as Vice President, Corporate Planning & Development since January 2017 and President, U.K. from 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 Senior Vice President, Global Operations as of August 2020, having previously served as Vice President, Corporate Planning & Development since June 2018. Prior to that, he served as Vice President, Mid-Continent Business Unit in the Lower 48 from September 2016 to 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.

## PART II

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

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

**Cash Dividends Per Share**

| | Dividends | |
|---|---|---|
| | **2020** | 2019 |
| First | $ **0.420** | 0.305 |
| Second | **0.420** | 0.305 |
| Third | **0.420** | 0.305 |
| Fourth | **0.430** | 0.420 |

| | |
|---|---|
| Number of Stockholders of Record at January 31, 2021* | 40,483 |

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

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

**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<br>Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1-31, 2020 | 4,805,220 | $ 34.68 | 4,805,220 | $ 14,483 |
| November 1-30, 2020 | - | - | - | 14,483 |
| December 1-31, 2020 | - | - | - | 14,483 |
| | 4,805,220 | $ 34.68 | 4,805,220 | |

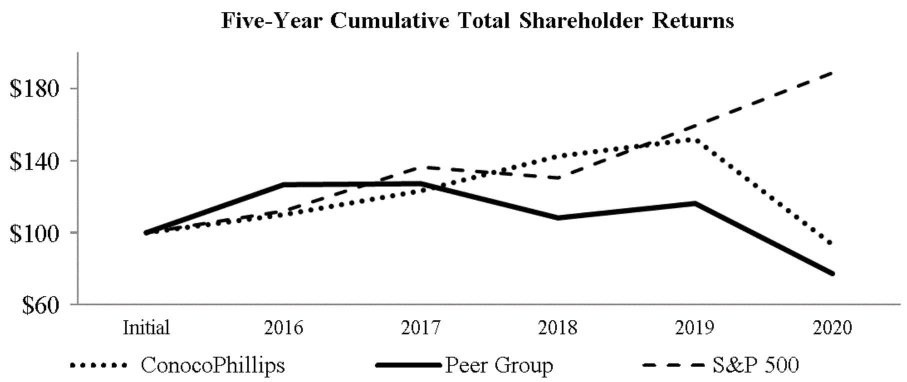
**There were no repurchases of common stock from company employees in connection with the company's broad-based employee incentive plans.*

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, 2020, we had repurchased $10.5 billion of shares. Repurchases are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Except as limited by applicable legal requirements, repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares. See "Item 1A—Risk Factors – Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

**Stock Performance Graph**

The following graph shows the cumulative TSR for ConocoPhillips' common stock in each of the five years from December 31, 2015 to December 31, 2020. The graph also compares the cumulative total returns for 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. For the 2019 Stock Performance Graph, Noble Energy was also presented within the peer group. However, due to Chevron's acquisition of Noble Energy completed in 2020, Noble Energy's performance has been excluded from all five years of the peer group performance.

The comparison assumes $100 was invested on December 31, 2015, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer group and assumes that all dividends were reinvested. The cumulative total returns of the peer group companies' common stock do not include the cumulative total return of ConocoPhillips' common stock. The stock price performance included in this graph is not necessarily indicative of future stock price performance.



## 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 75.*

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

### BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is an independent E&P company with operations and activities in 15 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe and Asia; LNG developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. Headquartered in Houston, Texas, at December 31, 2020, we employed approximately 9,700 people worldwide and had total assets of $63 billion.

**Completed Acquisition of Concho Resources Inc.**

On January 15, 2021, we completed our acquisition of Concho Resources Inc. (Concho), an independent oil and gas exploration and production company with operations across New Mexico and West Texas. The addition of complementary acreage in the Delaware and Midland Basins creates a sizeable Permian presence to augment our leading unconventional positions in the Eagle Ford and Bakken in the Lower 48 and the Montney in Canada.

Consideration for the all-stock transaction was valued at $13.1 billion, in which 1.46 shares of ConocoPhillips common stock was exchanged for each outstanding share of Concho common stock, resulting in the issuance of approximately 286 million shares of ConocoPhillips common stock. We also assumed $3.9 billion in aggregate principal amount of outstanding debt for Concho, which was recorded at fair value of $4.7 billion as of the closing date. The combined companies are expected to capture approximately $750 million of annual cost and capital savings by 2022. For additional information related to this transaction, see Note 25—Acquisition of Concho Resources Inc. in the Notes to Consolidated Financial Statements.

**Overview**

The energy landscape changed dramatically in 2020 with simultaneous demand and supply shocks that drove the industry into a severe downturn. The demand shock was triggered by the COVID-19 pandemic, which continues to have unprecedented social and economic consequences. Mitigation efforts to stop the spread of this highly-contagious disease include stay-at-home orders and business closures that caused sharp contractions in economic activity worldwide. The supply shock was triggered by disagreements between OPEC and Russia, beginning in early March 2020, which resulted in significant supply coming onto the market and an oil price war. These dual demand and supply shocks caused oil prices to collapse as we exited the first quarter of 2020.

As we entered the second quarter of 2020, predictions of COVID-19 driven global oil demand losses intensified, with forecasts of unprecedented demand declines. Based on these forecasts, OPEC plus nations held an emergency meeting, and in April they announced a coordinated production cut that was unprecedented in both its magnitude and duration. The OPEC plus agreement spans from May 2020 until April 2022, with the volume of production cuts easing over time. Additionally, non-OPEC plus countries, including the U.S., Canada, Brazil and other G-20 countries, announced organic reductions to production through the release of drilling rigs, frac crews, normal field decline and curtailments. Despite these planned production decreases, the supply cuts were not timely enough to overcome significant demand decline. Futures prices for April WTI closed under $20 a barrel for the first time since 2001, followed by May WTI settling below zero on the day before futures contracts expiry, as holders of May futures contracts struggled to exit positions and avoid taking physical delivery. As storage constraints approached, spot prices in April for certain North American landlocked grades of crude oil were in the single digits or even negative for particularly remote or low-grade crudes, while waterborne priced crudes such as Brent sold at a relative advantage. The extreme volatility experienced in the first half of the year settled down in the second half of the year, with WTI crude oil prices exiting the year near $50 per barrel.

Since the start of the severe downturn, we have closely monitored the market and taken prudent actions in response to this situation. We entered 2020 in a position of relative strength, with cash and cash equivalents of more than $5 billion, short-term investments of $3 billion, and an undrawn credit facility of $6 billion, totaling approximately $14 billion in available liquidity. Additionally, we had several entity and asset sales agreements in place, which generated $1.3 billion in proceeds from dispositions during 2020. For more information about the sales of our Australia-West and non-core Lower 48 assets, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements. This relative advantage allowed us to be measured in our response to the sudden change in business environment.

In March, we announced an initial set of actions to address the downturn and followed up with additional actions in April. The combined announcements reflected a reduction in our 2020 operating plan capital of $2.3 billion, a reduction to our operating costs of $600 million and suspension of our share repurchase program. These actions decreased uses of cash by approximately $5 billion in 2020. We also established a framework for evaluating our assets and implementing economic production curtailments considering the weakness in oil prices during the second quarter of 2020, which resulted in taking an additional significant step of voluntarily curtailing production, predominantly from operated North American assets. Due to our strong balance sheet, we were in an advantaged position to forgo some production and cash flow in anticipation of receiving higher cash flows for those volumes in the future.

In the second quarter, we curtailed production by an estimated 225 MBOED, with 145 MBOED of the curtailments from the Lower 48, 40 MBOED from Alaska and 30 MBOED from our Surmont operation in Canada. The remainder of the second-quarter curtailments were primarily in Malaysia. Other industry operators also cut production and development plans and as we progressed through the second quarter, certain stay-at-home restrictions eased, which partially restored lost demand, and WTI and Brent prices exited the second quarter around $40 per barrel. Based on our economic framework, we began restoring production from voluntary curtailments in July, and with oil stabilizing around $40 per barrel, we ended our curtailment program during the third quarter. Curtailments in the third quarter averaged approximately 90 MBOED, with 65 MBOED attributable to the Lower 48 and 15 MBOED to Surmont.

In August 2020, we acquired additional Montney acreage for cash consideration of $382 million, after customary post-closing adjustments. We also assumed $31 million in financing obligations for associated partially owned infrastructure. This acquisition consisted primarily of undeveloped properties and included 140,000 net acres in the liquids-rich Inga Fireweed asset Montney zone, which is directly adjacent to our existing Montney position. The transaction increased our Montney acreage position to approximately 295,000 net acres with a 100 percent working interest. See Note 4—Acquisitions and Dispositions in the Notes to Consolidated Financial Statements for additional information.

In October 2020, we announced an increase to our quarterly dividend from $0.42 per share to $0.43 per share and resumed share repurchases before suspending our share repurchase program upon entry into our definitive agreement to acquire Concho. We resumed shares repurchases in February 2021 after completion of our Concho acquisition. We ended the year with over $12 billion of liquidity, comprised of $3.0 billion in cash and cash equivalents, $3.6 billion in short-term investments, and available borrowings under our credit facility of $5.7 billion.

Our expectation is that commodity prices will remain cyclical and volatile, and a successful business strategy in the E&P industry must be resilient in lower price environments, at the same time retaining upside during periods of higher prices. While we are not impervious to current market conditions, we believe our decisive actions over the last several years of focusing on free cash flow generation, high-grading our asset base, lowering the cost of supply of our investment resource portfolio, and strengthening our balance sheet have put us in a strong relative position compared to our independent E&P peers. We remain committed to the core principles of our value proposition, namely, free cash flow generation, a strong balance sheet, commitment to differential returns of and on capital, and ESG leadership.

Our workforce and operations have adjusted to mitigate the impacts of the COVID-19 pandemic. We have operations in remote areas with confined spaces, such as offshore platforms, the North Slope of Alaska, Curtis Island in Australia, western Canada and Indonesia, where viruses could rapidly spread. Personnel are asked to perform a self-assessment for symptoms of illness each day and, when appropriate, are subject to more restrictive measures before traveling to and working on location. Staffing levels in certain operating locations have been reduced to minimize health risk exposure and increase social distancing. A portion of our office staff have continued to work successfully remotely, with offices around the world carefully designing and executing a flexible, phased reentry, following national, state and local guidelines. These mitigation measures have thus far been effective at reducing business operation disruptions. Workforce health and safety remains the overriding driver for our actions and we have demonstrated our ability to adapt to local conditions as warranted.

The marketing and supply chain side of our business has also adapted in response to COVID-19. Our commercial organization managed transportation commitments during our voluntary curtailment program. Our supply chain function is proactively working with vendors to ensure the continuity of our business operations, monitor distressed service and materials providers, capture deflation opportunities, and pursue cost reduction efforts. We also enhanced our focus on counterparty risk monitoring during this period and requested credit assurances when applicable.

Operationally, we remain focused on safely executing the business. In 2020, production of 1,127 MBOED generated cash provided by operating activities of $4.8 billion. We invested $4.7 billion into the business in the form of capital expenditures, including $0.5 billion of acquisition capital, and paid dividends to shareholders of $1.8 billion. Production decreased 221 MBOED or 16 percent in 2020, compared to 2019. Production excluding Libya for 2020 was 1,118 MBOED. Adjusting for estimated curtailments of approximately 80 MBOED; closed acquisitions and dispositions; and excluding Libya, production for 2020 would have been 1,176 MBOED, a decrease of 15 MBOED compared with 2019 production. This decrease was primarily due to normal field decline, partly offset by new wells online in the Lower 48, Canada, Norway, Alaska and China. Production from Libya averaged 9 MBOED as it was in force majeure during a significant portion of the year.

**Key Operating and Financial Summary**

Significant items during 2020 and recent announcements included the following:

- Enhanced both our portfolio and financial framework through the acquisition of Concho in an all-stock transaction, as well as purchasing bolt-on acreage in Canada and Lower 48.
- Full-year production, excluding Libya, of 1,118 MBOED; curtailed approximately 80 MBOED during the year.

- Cash provided by operating activities was $4.8 billion.
- Generated $1.3 billion in disposition proceeds from non-core asset sales.
- Distributed $1.8 billion in dividends and repurchased $0.9 billion of shares.
- Ended the year with cash and cash equivalents totaling $3.0 billion and short-term investments of $3.6 billion, equaling $6.6 billion in ending cash and cash equivalents and short-term investments.
- Announced two significant discoveries in Norway and achieved first production at Tor II; continued appraisal drilling and started up first pads and related infrastructure in Montney.
- Adopted a Paris-aligned climate risk framework with ambition to achieve net-zero operated emissions by 2050 as part of our commitment to ESG excellence.
- Recognized impairments of proved and unproved properties totaling $1.3 billion after-tax.

**Business Environment**

Brent crude oil prices averaged $42 per barrel in 2020, compared with $64 per barrel in 2019. The energy industry has periodically experienced this type of volatility due to fluctuating supply-and-demand conditions and such volatility may persist for the foreseeable future. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Our strategy is to create value through price cycles by delivering on the foundational principles that underpin our value proposition; free cash flow generation, a strong balance sheet, commitment to differential returns of and on capital, and ESG leadership.

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

- Free cash flow generation. This is a core principle of our value proposition. Our goal is to achieve strong free cash flow by exercising capital discipline, controlling our costs, and safely and reliably delivering production. Throughout the price cycles, we expect to make capital investments sufficient to sustain production. Free cash flow provides funds that are available to return to shareholders, strengthen the balance sheet to deliver on our priorities through the price cycles, or reinvest back into the business for future cash flow expansion.

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

    In February 2021, we announced 2021 operating plan capital for the combined company of $5.5 billion. The plan includes $5.1 billion to sustain current production and $0.4 billion for investment in major projects, primarily in Alaska, in addition to ongoing exploration appraisal activity.

    The operating plan capital budget of $5.5 billion is expected to deliver production from the combined company of approximately 1.5 MMBOED in 2021. This production guidance excludes Libya.

- Control costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment. The ability to control our operating and overhead costs impacts our ability to deliver strong cash from operations. In 2020, our production and operating expenses were 18 percent lower than 2019, primarily due to decreased wellwork and transportation costs resulting from production curtailments across our North American operated assets as well as the absence of costs related to our U.K. and Australia-West divestitures. For more information related to our U.K. and Australia-West divestitures, see note 4—Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

  At the time of the Concho acquisition announcement in October 2020, we announced planned cost reductions and quantified $350 million of annual expense savings expected to be achieved by 2022. These reductions included approximately $150 million due to streamlining our internal organization to appropriate levels given the current industry environment and recent asset sales; $100 million of G&A and G&G due to a refocused exploration program; and $100 million of redundant G&A costs on a combined basis related to the Concho acquisition. Subsequent to the transaction announcement, we identified $250 million of further cost reductions from the combined companies to be achieved by 2022.

- Optimize our portfolio. In January 2021, we completed the acquisition of Concho and significantly increased our unconventional portfolio with years of low cost of supply investments. The addition of complementary acreage in the Delaware and Midland basins creates a sizeable Permian presence to augment our leading unconventional positions in the Eagle Ford and Bakken in the Lower 48. We added to our unconventional Montney position with an asset acquisition that consisted primarily of undeveloped properties directly adjacent to our existing acreage.

  These acquisitions followed several non-core asset sales earlier in the year including Australia-West in our Asia Pacific segment, and Niobrara and Waddell Ranch in the Lower 48. We managed the portfolio well during a turbulent year, with asset sales entered at the end of 2019 generating $1.3 billion of proceeds from dispositions in the first half of 2020, followed by opportunistic acquisitions of unconventional assets in the second half of 2020 after commodity prices had dropped. We will continue to evaluate our assets to determine whether they compete for capital within our portfolio and will optimize the portfolio as necessary, directing capital towards the most competitive investments.

- A strong balance sheet. We believe balance sheet strength is critical in a cyclical business such as ours. Our strong operating performance buffered by a solid balance sheet enables us to deliver on our priorities through the price cycles. Our priorities include execution of our development plans, maintaining a growing dividend, and returning competitive returns of capital to shareholders.

- Commitment to differential returns of and on capital. We believe in delivering value to our shareholders via a growing, sustainable dividend supplemented by additional returns of capital, including share repurchases. In 2020, we paid dividends on our common stock of approximately $1.8 billion and repurchased $0.9 billion of our common stock. Combined, our dividend and repurchases represented 57 percent of our net cash provided by operating activities. Since we initiated our current share repurchase program in late 2016, we have repurchased 189 million shares for $10.5 billion, which represents approximately 15 percent of shares outstanding as of September 30, 2016. As of December 31, 2020, $14.5 billion of repurchase authority remained of the $25 billion share repurchase program our Board of Directors had authorized. Repurchases are made at management's discretion, at prevailing prices, subject to market conditions and other factors. See “Item 1A—Risk Factors Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.”

In October 2020, we announced that our Board of Directors approved an increase to our quarterly dividend of $0.42 per share to $0.43 per share. In February 2021, we resumed share repurchases after the completion of our Concho acquisition.

- ESG Leadership. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth. Demonstrating our commitment to sustainability and environmental stewardship, in October 2020, we announced our adoption of a Paris-aligned climate risk framework as part of our continued leadership in ESG excellence. This comprehensive climate risk strategy should enable us to sustainably meet global energy demand while delivering competitive returns through the energy transition. We have set a target to reduce our gross operated (scope 1 and 2) emissions intensity by 35 to 45 percent from 2016 levels by 2030, with an ambition to achieve net zero by 2050 for operated emissions. We are advocating for reduction of scope 3 end-use emissions intensity through our support for a U.S. carbon price and reaffirmed our commitment to the Climate Leadership Council. We have joined the World Bank Flaring Initiative to work towards zero routine flaring of gas by 2030 and are the first U.S.-based oil and gas company to adopt a Paris-aligned climate risk strategy.

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

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

  As required by current authoritative guidelines, the estimated future date when an asset will reach 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 negative 86 percent in 2020, reflecting the impact of lower prices, which reduced reserves by approximately 600 MMBOE. Our organic reserve replacement, which excluded a net decrease of 7 MMBOE from sales and purchases, was negative 84 percent in 2020.

  In the three years ended December 31, 2020, our reserve replacement was 59 percent, primarily impacted by lower prices in 2020. Our organic reserve replacement during the three years ended December 31, 2020, which excluded a net increase of 89 MMBOE related to sales and purchases, was 53 percent.

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

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

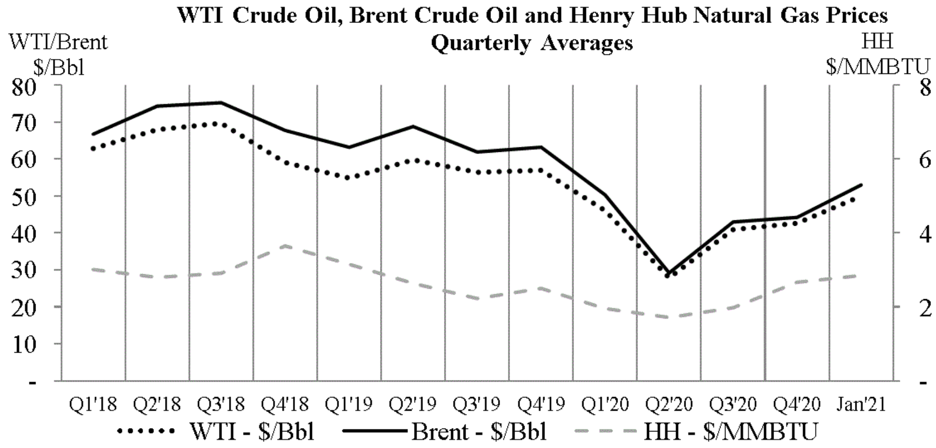
  We have embraced the digital transformation and are using digital innovations to work and operate more efficiently. Predictive analytics have been adopted in our operations and planning process. Artificial intelligence, machine learning and deep learning are being used for emissions monitoring, seismic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

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

*Other Factors Affecting Profitability*

Other significant factors that can affect our profitability include:

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




Brent crude oil prices averaged $41.68 per barrel in 2020, a decrease of 35 percent compared with $64.30 per barrel in 2019. Similarly, WTI crude oil prices decreased 31 percent from $57.02 per barrel in 2019 to $39.37 per barrel in 2020. Crude oil prices were lower due to the dual demand and supply shocks. The demand shock was triggered by the COVID-19 pandemic, which continues to have unprecedented social and economic consequences. The supply shock was triggered by disagreements between OPEC and Russia, beginning in early March 2020, which resulted in significant supply coming onto the market and created higher inventory levels.

Henry Hub natural gas prices decreased 21 percent from an average of $2.63 per MMBTU in 2019 to $2.08 per MMBTU in 2020. Henry Hub prices were depressed due to high storage levels and weak demand.

Our realized bitumen price decreased 75 percent from an average of $31.72 per barrel in 2019 to $8.02 per barrel in 2020. The decrease was largely driven by weakness in WTI, reflective of impacts from the COVID-19 pandemic. The WCS differential to WTI at Hardisty remained fairly flat as curtailment orders imposed by the Alberta Government, which limited production from the province, continued throughout 2020. We continue to optimize bitumen price realizations through improvements in alternate blend capability which results in lower diluent costs and access to the U.S. Gulf Coast market through rail and pipeline contracts.

Our worldwide annual average realized price decreased 34 percent from $48.78 per BOE in 2019 to $32.15 per BOE in 2020 primarily due to lower realized oil, natural gas and bitumen prices.

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

- Impairments. We participate in a capital-intensive industry. At times, our PP&E and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. As we optimize our assets in the future, it is reasonably possible we may incur future losses upon sale or impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. For additional information on our impairments, see Note 7—Suspended Wells and Exploration Expenses and Note 8—Impairments, in the Notes to Consolidated Financial Statements.

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

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

## Outlook

*Production and Capital*
In February 2021, we announced 2021 operating plan capital for the combined company of $5.5 billion. The plan includes $5.1 billion to sustain current production and $0.4 billion for investment in major projects, primarily in Alaska, in addition to ongoing exploration appraisal activity.

The operating plan capital budget of $5.5 billion is expected to deliver production from the combined company of approximately 1.5 MMBOED in 2021. This production guidance excludes Libya.

*Restructuring*
As a result of the acquisition of Concho, we commenced a restructuring program in the first quarter of 2021 in association with combining the operations of the two companies. We expect to incur significant non-recurring transaction and acquisition-related costs in 2021 for employee severance payments; incremental pension benefit costs related to the workforce reductions; employee retention costs; employee relocations; fees paid to financial, legal, and accounting advisors; and filing fees. We currently cannot estimate these costs, as well as other unanticipated items, and expect to recognize the majority of these expenses in the first quarter of 2021.

## Operating Segments

We manage our operations through six operating segments, which are primarily defined by geographic 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

*Effective with the third quarter of 2020, we have restructured our segments to align with changes to our internal organization. The Middle East business was realigned from the Asia Pacific and Middle East segment to the Europe and North Africa segment. The segments have been renamed the Asia Pacific segment and the Europe, Middle East and North Africa segment. We have revised segment information disclosures and segment performance metrics presented within our results of operations for the current and prior years.*

*This section of the Form 10-K discusses year-to-year comparisons between 2020 and 2019. For discussion of year-to-year comparisons between 2019 and 2018, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Exhibit 99.1—, Item 7 filed with our Form 8-K filed on November 16, 2020.*

### Consolidated Results

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

| | Millions of Dollars | | |
|---|---|---|---|
| Years Ended December 31 | **2020** | 2019 | 2018 |
| Alaska | $ **(719)** | 1,520 | 1,814 |
| Lower 48 | **(1,122)** | 436 | 1,747 |
| Canada | **(326)** | 279 | 63 |
| Europe, Middle East and North Africa | **448** | 3,170 | 2,594 |
| Asia Pacific | **962** | 1,483 | 1,342 |
| Other International | **(64)** | 263 | 364 |
| Corporate and Other | **(1,880)** | 38 | (1,667) |
| Net income (loss) attributable to ConocoPhillips | $ **(2,701)** | 7,189 | 6,257 |

*2020 vs. 2019*

Net income (loss) attributable to ConocoPhillips decreased $9.9 billion in 2020. The decrease was mainly due to:

- Lower realized commodity prices.
- Lower sales volumes due to normal field decline, asset dispositions and production curtailments. For additional information related to dispositions, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- The absence of a $2.1 billion after-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries. For additional information, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- An unrealized loss of $855 million after-tax on our Cenovus Energy (CVE) common shares in 2020, as compared to a $649 million after-tax unrealized gain on those shares in 2019.
- A $648 million after-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs and an equity method investment related to our Alaska North Slope Gas asset. For additional information, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.
- Increased impairments primarily related to developed properties in our non-core assets which were written down to fair value due to lower commodity prices and development plan changes. For additional information, see Note 8—Impairments and Note 14—Fair Value Measurement in the Notes to Consolidated Financial Statements.
- The absence of other income of $317 million after-tax related to our settlement agreement with PDVSA.

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

- Lower production and operating expenses, primarily due to the absence of costs related to our U.K. and Australia-West divestitures and decreased wellwork and transportation costs resulting from production curtailments across our North American operated assets.
- A $597 million after-tax gain on dispositions related to our Australia-West divestiture.
- Lower DD&A expenses, primarily due to lower volumes related to normal field decline and production curtailments as well as impacts of our Australia-West and U.K. divestitures. Partly offsetting this decrease, was higher DD&A expenses due to price-related downward reserve revisions.

**Income Statement Analysis**

*2020 vs. 2019*

<u>Sales and other operating revenues</u> decreased 42 percent in 2020, mainly due to lower realized commodity prices and lower sales volumes. Sales volumes decreased due to normal field decline, production curtailments from our North American operated assets and the divestiture of our U.K. assets in the third quarter of 2019 and our Australia-West assets in the second quarter of 2020.

<u>Equity in earnings of affiliates</u> decreased $347 million in 2020, primarily due to lower earnings from QG3 and APLNG because of lower LNG prices. Partly offsetting this decrease was the absence of impairments related to equity method investments in our Lower 48 segment of $155 million and the absence of a $118 million deferred tax adjustment at QG3, reported in our Europe, Middle East and North Africa segment.

<u>Gain on dispositions</u> decreased $1.4 billion in 2020, primarily due to the absence of a $1.7 billion before-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries. Partly offsetting the decrease was a $587 million before-tax gain associated with our Australia-West divestiture. For more information related to these dispositions, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

<u>Other income (loss)</u> decreased $1.9 billion in 2020, primarily due to a before-tax unrealized loss of $855 million on our CVE common shares in 2020, and the absence of a $649 million before-tax unrealized gain on those shares in 2019. Additionally, other income (loss) decreased due to the absence of $325 million before-tax related to our settlement agreement with PDVSA.

For discussion of our CVE shares, see Note 6—Investment in Cenovus Energy in the Notes to Consolidated Financial Statements. For discussion of our PDVSA settlement, see Note 12—Contingencies and Commitments in the Notes to Consolidated Financial Statements.

<u>Purchased commodities</u> decreased 32 percent in 2020, primarily due to lower natural gas and crude oil prices; lower crude oil and natural gas volumes purchased; and the divestiture of our U.K. assets in the third quarter of 2019 and our Australia-West assets in the second quarter of 2020.

<u>Production and operating expenses</u> decreased $978 million in 2020, primarily due to reduced activities and transportation costs associated with lower activity across our North American operated assets in response to the low commodity price environment and the absence of costs related to our U.K. and Australia-West divestitures.

<u>Selling, general and administrative expenses</u> decreased $126 million in 2020, primarily due to lower costs associated with compensation and benefits, including mark to market impacts of certain key employee compensation programs.

Exploration expenses increased $714 million in 2020, primarily due to an $828 million before-tax impairment for the entire carrying value of capitalized undeveloped leasehold costs related to our Alaska North Slope Gas asset. Partly offsetting this increase, was the absence of a $141 million before-tax leasehold impairment expense due to our decision to discontinue exploration activities in the Central Louisiana Austin Chalk trend. For additional information, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.

Impairments increased $408 million in 2020, primarily related to developed properties in our non-core assets which were written down to fair value due to lower commodity prices and development plan changes. For additional information, see Note 8—Impairments and Note 14—Fair Value Measurement in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased $199 million in 2020, primarily due to lower commodity prices and volumes.

Foreign currency transaction (gains) losses decreased $138 million in 2020, due to gains recognized from foreign currency derivatives and other foreign currency remeasurements. For additional information, see Note 13—Derivative and Financial Instruments in the Notes to Consolidated Financial Statements.

See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

**Summary Operating Statistics**

| | | 2020 | 2019 | 2018 |
|---|---|---|---|---|
| **Average Net Production** | | | | |
| Crude oil (MBD) | | | | |
| Consolidated Operations | | **555** | 692 | 639 |
| Equity affiliates | | **13** | 13 | 14 |
| Total crude oil | | **568** | 705 | 653 |
| | | | | |
| Natural gas liquids (MBD) | | | | |
| Consolidated Operations | | **97** | 107 | 95 |
| Equity affiliates | | **8** | 8 | 7 |
| Total natural gas liquids | | **105** | 115 | 102 |
| | | | | |
| Bitumen (MBD) | | **55** | 60 | 66 |
| | | | | |
| Natural gas (MMCFD) | | | | |
| Consolidated Operations | | **1,339** | 1,753 | 1,743 |
| Equity affiliates | | **1,055** | 1,052 | 1,031 |
| Total natural gas | | **2,394** | 2,805 | 2,774 |
| | | | | |
| **Total Production** (MBOED) | | **1,127** | 1,348 | 1,283 |

| | | Dollars Per Unit | | |
|---|---|---|---|---|
| **Average Sales Prices** | | | | |
| Crude oil (per bbl) | | | | |
| Consolidated Operations | $ | **39.56** | 60.98 | 68.03 |
| Equity affiliates | | **39.02** | 61.32 | 72.49 |
| Total crude oil | | **39.54** | 60.99 | 68.13 |
| | | | | |
| Natural gas liquids (per bbl) | | | | |
| Consolidated Operations | | **12.90** | 18.73 | 29.03 |
| Equity affiliates | | **32.69** | 36.70 | 45.69 |
| Total natural gas liquids | | **14.61** | 20.09 | 30.48 |
| | | | | |
| Bitumen (per bbl) | | **8.02** | 31.72 | 22.29 |
| | | | | |
| Natural gas (per mcf) | | | | |
| Consolidated Operations | | **3.17** | 4.25 | 5.40 |
| Equity affiliates | | **3.71** | 6.29 | 6.06 |
| Total natural gas | | **3.41** | 5.03 | 5.65 |

| | | Millions of Dollars | | |
|---|---|---|---|---|
| **Worldwide Exploration Expenses** | | | | |
| General and administrative; geological and geophysical, lease rental, and other | $ | **374** | 322 | 274 |
| Leasehold impairment | | **868** | 221 | 56 |
| Dry holes | | **215** | 200 | 39 |
| | $ | **1,457** | 743 | 369 |

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwide basis. At December 31, 2020, our operations were producing in the U.S., Norway, Canada, Australia, Indonesia, China, Malaysia, Qatar and Libya.

*2020 vs. 2019*

Total production, including Libya, of 1,127 MBOED decreased 221 MBOED or 16 percent in 2020 compared with 2019, primarily due to:

- Normal field decline.
- The divestiture of our U.K. assets in the third quarter of 2019 and our Australia-West assets in the second quarter of 2020.
- Production curtailments of approximately 80 MBOED, primarily from North American operated assets and Malaysia, in response to the low crude oil price environment.
- Less production in Libya due to the forced shutdown of the Es Sider export terminal and other eastern export terminals after a period of civil unrest.

The decrease in production during 2020 was partly offset by:

- New wells online in the Lower 48, Canada, Norway, Alaska and China.

Production excluding Libya for 2020 was 1,118 MBOED. Adjusting for estimated curtailments of approximately 80 MBOED and closed acquisitions and dispositions, production for 2020 would have been 1,176 MBOED, a decrease of 15 MBOED compared with 2019. This decrease was primarily due to normal field decline, partly offset by new wells online in the Lower 48, Canada, Norway, Alaska and China. Production from Libya averaged 9 MBOED as it was in force majeure during a significant portion of the year.

**Alaska**

| | | 2020 | 2019 | 2018 |
|---|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** (millions of dollars) | $ | **(719)** | 1,520 | 1,814 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **181** | 202 | 171 |
| Natural gas liquids (MBD) | | **16** | 15 | 14 |
| Natural gas (MMCFD) | | **10** | 7 | 6 |
| **Total Production** (MBOED) | | **198** | 218 | 186 |
| **Average Sales Prices** | | | | |
| Crude oil ($ per bbl) | $ | **42.12** | 64.12 | 70.86 |
| Natural gas ($ per mcf) | | **2.91** | 3.19 | 2.48 |

The Alaska segment primarily explores for, produces, transports and markets crude oil, NGLs and natural gas. In 2020, Alaska contributed 28 percent of our consolidated liquids production and less than 1 percent of our consolidated natural gas production.

*2020 vs. 2019*

*Net Income (Loss) Attributable to ConocoPhillips*
Alaska reported a loss of $719 million in 2020, compared with earnings of $1,520 million in 2019. Earnings were negatively impacted by:

- Lower realized crude oil prices.
- A $648 million after-tax impairment associated with the carrying value of our Alaska North Slope Gas assets. For additional information, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.
- Lower sales volumes, primarily due to normal field decline and production curtailments at our operated assets on the North Slope—the Greater Kuparuk Area (GKA) and Western North Slope (WNS).
- Higher DD&A expenses, primarily from increased DD&A rates due to price-related downward reserve revisions, partly offset by lower production volumes.
- Increased exploration expenses, primarily due to higher dry hole costs and expenses related to the early cancellation of our winter exploration program.

Earnings were positively impacted by:

- Lower production and operating expenses, primarily associated with lower transportation and terminaling costs as well as lower activities across our assets.

*Production*
Average production decreased 20 MBOED in 2020 compared with 2019, primarily due to:

- Normal field decline.
- Production curtailments at our operated assets on the North Slope—GKA and WNS—of 8 MBOED in response to the low crude oil price environment.

These production decreases were partly offset by:

- Lower downtime due to the absence of planned turnarounds at the Greater Prudhoe Area.
- New wells online at our operated assets on the North Slope—GKA and WNS.

**Lower 48**

| | | 2020 | 2019 | 2018 |
|---|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| (millions of dollars) | $ | **(1,122)** | 436 | 1,747 |
| | | | | |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **213** | 266 | 229 |
| Natural gas liquids (MBD) | | **74** | 81 | 69 |
| Natural gas (MMCFD) | | **585** | 622 | 596 |
| | | | | |
| **Total Production** (MBOED) | | **385** | 451 | 397 |
| | | | | |
| **Average Sales Prices** | | | | |
| Crude oil ($ per bbl) | $ | **35.17** | 55.30 | 62.99 |
| Natural gas liquids ($ per bbl) | | **12.13** | 16.83 | 27.30 |
| Natural gas ($ per mcf) | | **1.65** | 2.12 | 2.82 |

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf of Mexico. During 2020, the Lower 48 contributed 40 percent of our consolidated liquids production and 44 percent of our consolidated natural gas production.

*2020 vs. 2019*

*Net Income (Loss) Attributable to ConocoPhillips*
Lower 48 reported a loss of $1,122 million in 2020, compared with earnings of $436 million in 2019. Earnings were negatively impacted by:

- Lower realized crude oil, NGL and natural gas prices.
- Lower crude oil sales volumes due to normal field decline and production curtailments.
- Higher impairments, primarily related to developed properties in our non-core assets which were written down to fair value due to lower commodity prices and development plan changes. See Note 8—Impairments and Note 14—Fair Value Measurement, for additional information.

Earnings were positively impacted by:

- Lower exploration expenses, primarily due to the absence of a combined $197 million after-tax of leasehold impairment and dry hole costs associated with our decision to discontinue exploration activities in the Central Louisiana Austin Chalk.
- Lower DD&A expenses, primarily due to normal field decline and production curtailments, partly offset by increased DD&A rates due to price-related downward reserve revisions.
- Lower production and operating expenses, primarily due to lower activities driven by production curtailments in response to the low price environment and disposition impacts.
- Lower taxes other than income taxes, primarily due to lower realized prices and volumes.

*Production*
Total average production decreased 66 MBOED in 2020 compared with 2019, primarily due to:

- Normal field decline.
- Production curtailments of approximately 55 MBOED in response to the low crude oil price environment.

These production decreases were partly offset by:

- New wells online from the Eagle Ford, Permian and Bakken.

## Canada

| | | 2020* | 2019** | 2018** |
|---|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| (millions of dollars) | $ | **(326)** | 279 | 63 |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **6** | 1 | 1 |
| Natural gas liquids (MBD) | | **2** | - | 1 |
| Bitumen (MBD) | | **55** | 60 | 66 |
| Natural gas (MMCFD) | | **40** | 9 | 12 |
| **Total Production** (MBOED) | | **70** | 63 | 70 |
| **Average Sales Prices** | | | | |
| Crude oil ($ per bbl) | $ | **23.57** | 40.87 | 48.73 |
| Natural gas liquids ($ per bbl) | | **5.41** | 19.87 | 43.70 |
| Bitumen ($ per bbl) | | **8.02** | 31.72 | 22.29 |
| Natural gas ($ per mcf) | | **1.21** | 0.49 | 1.00 |

**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. GulfCoast.*

Our Canadian operations consist of the Surmont oil sands development in Alberta and the liquids-rich Montney unconventional play in British Columbia. In 2020, Canada contributed 9 percent of our consolidated liquids production and 3 percent of our consolidated natural gas production.

*2020 vs. 2019*

*Net Income (Loss) Attributable to ConocoPhillips*
Canada operations reported a loss of $326 million in 2020 compared with earnings of $279 million in 2019. Earnings decreased mainly due to:
- Lower realized bitumen prices.
- Higher DD&A expenses, primarily due to increased volumes and DD&A rates from Montney production.
- Lower bitumen sales due to production curtailments at Surmont.

Earnings were positively impacted by:
- Increased Montney production from Pad 1 & 2 wells online and partial year production from the Kelt acquisition completed in August of 2020.

*Production*
Total average production increased 7 MBOED in 2020 compared with 2019. The production increase was primarily due to:
- Increased liquids and natural gas production from Montney Pad 1 & 2 wells online and partial year production from the Kelt acquisition completed in August of 2020.
- Decreased mandated production curtailments imposed by the Alberta government.

The production increase was partly offset by:
- Lower bitumen production, primarily due to voluntary curtailments at Surmont in response to the low price environment of 12 MBOED.

**Europe, Middle East and North Africa**

| | | 2020 | 2019* | 2018* |
|---|---|---|---|---|
| **Net Income Attributable to ConocoPhillips** | | | | |
| (millions of dollars) | $ | **448** | 3,170 | 2,594 |
| *Consolidated Operations* | | | | |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **86** | 138 | 149 |
| Natural gas liquids (MBD) | | **4** | 7 | 8 |
| Natural gas (MMCFD) | | **275** | 478 | 503 |
| **Total Production** (MBOED) | | **136** | 224 | 241 |
| **Average Sales Prices** | | | | |
| Crude oil ($ per bbl) | $ | **43.30** | 64.94 | 70.71 |
| Natural gas liquids ($ per bbl) | | **23.27** | 29.37 | 36.87 |
| Natural gas ($ per mcf) | | **3.23** | 4.92 | 7.65 |

**Prior periods have been updated to reflect the Middle East Business Unit moving from Asia Pacific to the Europe, Middle East and North Africa segment. See Note 24—Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements for additional information.*

The Europe, Middle East and North Africa segment consists of operations principally located in the Norwegian sector of the North Sea; the Norwegian Sea; Qatar; Libya; and commercial and terminalling operations in the U.K. In 2020, our Europe, Middle East and North Africa operations contributed 13 percent of our consolidated liquids production and 20 percent of our consolidated natural gas production.

*2020 vs. 2019*

*Net Income Attributable to ConocoPhillips*
Earnings for Europe, Middle East and North Africa operations of $448 million decreased $2,722 million in 2020 compared with 2019. The decrease in earnings was primarily due to:

- The absence of a $2.1 billion after-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries. For additional information, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- Lower equity in earnings of affiliates, primarily due to lower LNG sales prices.
- Lower realized crude oil prices in Norway.

In the fourth quarter of 2020, the effective tax rate within our equity method investment in the Europe, Middle East and North Africa segment increased.

*Consolidated Production*
Average consolidated production decreased 88 MBOED in 2020, compared with 2019. The decrease was mainly due to:

- The absence of production related to our U.K. disposition in the third quarter of 2019.
- Lower volumes from Libya due to a cessation of production following a period of civil unrest.
- Normal field decline.

These production decreases were partly offset by:

- New wells online in Norway.

**Asia Pacific**

| | | 2020 | 2019* | 2018* |
|---|---|---|---|---|
| **Net Income Attributable to ConocoPhillips** (millions of dollars) | $ | **962** | 1,483 | 1,342 |
| *Consolidated Operations* | | | | |
| **Average Net Production** | | | | |
| Crude oil (MBD) | | **69** | 85 | 89 |
| Natural gas liquids (MBD) | | **1** | 4 | 3 |
| Natural gas (MMCFD) | | **429** | 637 | 626 |
| **Total Production** (MBOED) | | **141** | 196 | 196 |
| **Average Sales Prices** | | | | |
| Crude oil ($ per bbl) | $ | **42.84** | 65.02 | 70.93 |
| Natural gas liquids ($ per bbl) | | **33.21** | 37.85 | 47.20 |
| Natural gas ($ per mcf) | | **5.39** | 5.91 | 6.15 |

**Prior periods have been updated to reflect the Middle East Business Unit moving from Asia Pacific to the Europe, Middle East and North Africa segment. See Note 24—Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements for additional information.*

The Asia Pacific segment has operations in China, Indonesia, Malaysia and Australia. During 2020, Asia Pacific contributed 10 percent of our consolidated liquids production and 32 percent of our consolidated natural gas production.

*2020 vs. 2019*

*Net Income Attributable to ConocoPhillips*
Asia Pacific reported earnings of $962 million in 2020, compared with $1,483 million in 2019. The decrease in earnings was mainly due to:

- Lower sales volumes, primarily from lower LNG sales due to the Australia-West divestiture; lower crude oil sales volumes in Malaysia, primarily due to production curtailments; and lower crude oil sales volumes in China due to the expiration of the Panyu production license. For more information related to our Australia-West divestiture, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.
- Lower realized commodity prices.
- Lower equity in earnings of affiliates from APLNG, mainly due to lower LNG sales prices.
- The absence of a $164 million income tax benefit related to deepwater incentive tax credits from the Malaysia Block G.

Earnings were positively impacted by:

- A $597 million after-tax gain on disposition related to our Australia-West divestiture.

*Consolidated Production*
Average consolidated production decreased 28 percent in 2020, compared with 2019. The decrease was primarily due to:

- The divestiture of our Australia-West assets.
- Normal field decline.
- Higher unplanned downtime due to the rupture of a third-party pipeline impacting gas production from the Kebabangan Field in Malaysia.
- The expiration of the Panyu production license in China.
- Production curtailments of 4 MBOED in Malaysia.

These production decreases were partly offset by:

- Development activity at Bohai Bay in China and Gumusut in Malaysia.

**Other International**

| | | **2020** | 2019 | 2018 |
|---|---|---|---|---|
| **Net Income (Loss) Attributable to ConocoPhillips** (millions of dollars) | **$** | **(64)** | 263 | 364 |

The Other International segment includes exploration activities in Colombia and Argentina and 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.

*2020 vs. 2019*

Other International operations reported a loss of $64 million in 2020, compared with earnings of $263 million in 2019. The decrease in earnings was primarily due to:

- The absence of $317 million after-tax in other income from a settlement award with PDVSA associated with prior operations in Venezuela. For additional information related to this settlement award, see Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.
- Increased exploration expenses, primarily due to dry hole costs and a full impairment of capitalized undeveloped leasehold costs in Colombia.

**Corporate and Other**

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| Net interest | $ | **(662)** | (604) | (680) |
| Corporate general and administrative expenses | | **(200)** | (252) | (91) |
| Technology | | **(26)** | 123 | 109 |
| Other | | **(992)** | 771 | (1,005) |
| | $ | **(1,880)** | 38 | (1,667) |

*2020 vs. 2019*

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest expense increased $58 million in 2020 compared with 2019, primarily due to lower interest income related to lower cash and cash equivalent balances and yield.

Corporate G&A expenses include compensation programs and staff costs. These costs decreased by $52 million in 2020 compared with 2019, primarily due to mark to market adjustments associated with certain compensation programs.

Technology includes our investment in new technologies or businesses, as well as licensing revenues. Activities are focused on both conventional and tight oil reservoirs, shale gas, heavy oil, oil sands, enhanced oil recovery and LNG. Earnings from Technology decreased by $149 million in 2020 compared with 2019, primarily due to lower licensing revenues.

The category “Other” includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment, premiums incurred on the early retirement of debt, unrealized holding gains or losses on equity securities, and pension settlement expense. Earnings in “Other” decreased by $1,763 million in 2020 compared with 2019, primarily due to:

- An unrealized loss of $855 million after-tax on our CVE common shares in 2020, compared with a $649 million after-tax unrealized gain in 2019.
- The absence of a $151 million tax benefit related to the revaluation of deferred tax assets following finalization of rules related to the 2017 Tax Cuts and Jobs Act. See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information related to the 2017 Tax Cuts and Jobs Act.

## CAPITAL RESOURCES AND LIQUIDITY

### Financial Indicators

| | Millions of Dollars Except as Indicated | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Net cash provided by operating activities | $ **4,802** | 11,104 | 12,934 |
| Cash and cash equivalents | **2,991** | 5,088 | 5,915 |
| Short-term investments | **3,609** | 3,028 | 248 |
| Short-term debt | **619** | 105 | 112 |
| Total debt | **15,369** | 14,895 | 14,968 |
| Total equity | **29,849** | 35,050 | 32,064 |
| Percent of total debt to capital* | **34 %** | 30 | 32 |
| Percent of floating-rate debt to total debt | **7 %** | 5 | 5 |

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, proceeds from asset sales, our commercial paper and credit facility programs and our ability to sell securities using our shelf registration statement. In 2020, the primary uses of our available cash were $4,715 million to support our ongoing capital expenditures and investments program; $1,831 million to pay dividends on our common stock; $892 million to repurchase our common stock; and $658 million for net purchase of investments. During 2020, cash and cash equivalents decreased by $2,097 million to $2,991 million.

We entered the year with a strong balance sheet including cash and cash equivalents of over $5 billion, short-term investments of $3 billion, and an undrawn credit facility of $6 billion, totaling approximately $14 billion in available liquidity. This strong foundation allowed us to be measured in our response to the sudden change in business environment as we exited the first quarter of 2020. In response to the oil market downturn that began in early 2020, we announced the following capital, share repurchase and operating cost reductions. We reduced our 2020 operating plan capital expenditures by a total of $2.3 billion, or approximately thirty-five percent of the original guidance. We suspended our share repurchase program, further reducing cash outlays by approximately $2 billion. We also reduced our operating costs by approximately $0.6 billion, or roughly ten percent of the original 2020 guidance. Collectively, these actions represent a reduction in 2020 cash uses of approximately $5 billion versus the original operating plan.

Considering the weakness in oil prices during the second quarter of 2020, we established a framework for evaluating and implementing economic curtailments, which resulted in taking an additional significant step of curtailing production, predominantly from operated North American assets. Due to our strong balance sheet, we were in an advantaged position to forgo some production and cash flow in anticipation of receiving higher cash flows for those volumes in the future. Based on our economic criteria, we began restoring production from voluntary curtailments in July, and with oil prices stabilizing around $40 per barrel, we ended our curtailment program by the end of the third quarter.

In the fourth quarter of 2020, we resumed share repurchases, repurchasing $0.2 billion of shares in October, before suspending our share repurchase program upon entry into a definitive agreement to acquire Concho. We resumed share repurchases in February 2021 after completion of our Concho acquisition.

As of December 31, 2020, we had cash and cash equivalents of $3.0 billion, short-term investments of $3.6 billion, and available borrowing capacity under our credit facility of $5.7 billion, totaling over $12 billion of liquidity. We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the “Significant Changes in Capital” section, will be sufficient to 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*
During 2020, cash provided by operating activities was $4,802 million, a 57 percent decrease from 2019. The decrease was primarily due to lower realized commodity prices, normal field decline, production curtailments, the divestiture of our U.K. and Australia-West assets, and the absence in 2020 of collections under our settlement agreement with PDVSA, partially offset by lower production and operating expenses.

Our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, 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 1,127 MBOED in 2020. Full-year production excluding Libya averaged 1,118 MBOED in 2020. Adjusting for estimated curtailments of approximately 80 MBOED; closed acquisitions and dispositions; and excluding Libya; production for 2020 was 1,176 MBOED. Production in 2021 is expected to be approximately 1.5 MMBOED, reflecting the impact from the Concho acquisition. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing 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, as shown in our supplemental reserve table disclosures. Our reserve replacement was negative 86 percent in 2020, reflecting the impact of lower prices, which reduced reserves by approximately 600 MMBOE. Our organic reserve replacement, which excluded a net decrease of 7 MMBOE from sales and purchases, was negative 84 percent in 2020.

In the three years ended December 31, 2020, our reserve replacement was 59 percent, reflecting the impact of lower prices in 2020. Our organic reserve replacement during the three years ended December 31, 2020, which excluded a net increase of 89 MMBOE related to sales and purchases, was 53 percent.

For additional information about our 2021 capital budget, see the “2021 Capital Budget” section within “Capital Resources and Liquidity” and for additional information on proved reserves, including both developed and undeveloped reserves, see the “Oil and Gas Operations” section of this report.

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

*Investing Activities*
In 2020, we invested $4.7 billion in capital expenditures, of which $0.5 billion consisted of strategic acquisitions, including additional Montney acreage. Capital expenditures invested in 2019 and 2018 were $6.6 billion and $6.8 billion, respectively. For information about our capital expenditures and investments, see the “Capital Expenditures and Investments” section.

We invest in short-term investments as part of our cash investment strategy, the primary objective of which is to protect principal, maintain liquidity and provide yield and total returns; these investments include time deposits, commercial paper as well as debt securities classified as available for sale. Funds for short-term needs to support our operating plan and provide resiliency to react to short-term price volatility are invested in highly liquid instruments with maturities within the year. Funds we consider available to maintain resiliency in longer term price downturns and to capture opportunities outside a given operating plan may be invested in instruments with maturities greater than one year. For additional information, see Note 1–Accounting Policies and Note 13–Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Investing activities in 2020 included net purchases of $658 million of investments, of which $420 million was invested in short-term instruments and $238 million was invested in long-term instruments. Investing activities in 2019 included net purchases of $2.9 billion of investments, of which $2.8 billion was invested in short-term instruments and $0.1 billion was invested in long-term instruments. For additional information, see Note 13—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Proceeds from asset sales in 2020 were $1.3 billion. We received cash proceeds of $765 million for the divestiture of our Australia-West assets and operations, with another $200 million payment due upon final investment decision of the proposed Barossa development project. We also received proceeds of $359 million and $184 million for the sale of our Niobrara interests and Waddell Ranch interests in the Lower 48, respectively.

Proceeds from asset sales in 2019 were $3.0 billion, including $2.2 billion for the sale of two ConocoPhillips U.K. subsidiaries and $350 million for the sale of our 30 percent interest in the Greater Sunrise Fields. Proceeds from assets sales in 2018 were $1.1 billion, including several non-core assets in the Lower 48, as well as the sale of a ConocoPhillips subsidiary which held 16.5 percent of our 24 percent interest in the Clair Field in the U.K. For additional information on our dispositions, see Note 4—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

*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 the ConocoPhillips Company's ability to issue up to $6.0 billion of commercial paper, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. With $300 million of commercial paper outstanding and no direct borrowings or letters of credit, we had $5.7 billion in available borrowing capacity under the revolving credit facility at December 31, 2020. We may consider issuing additional commercial paper in the future to supplement our cash position.

In October 2020, Moody's affirmed its rating of our senior long-term debt of "A3" with a "stable" outlook, and affirmed its rating of our short-term debt as "Prime-2." In January 2021, Fitch affirmed its rating of our long-term debt as "A" with a "stable" outlook and affirmed its rating of our short-term debt as "F1+." 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 downgraded its rating of our short-term debt from “A-1” to “A-2.” We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, upon downgrade of our credit ratings. If our credit ratings are downgraded from their current levels, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us from accessing 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, 2020 and 2019, we had direct bank letters of credit of $249 million and $277 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of credit ratings downgrades, we may be required to post additional letters of credit.

On January 15, 2021, we completed the acquisition of Concho in an all-stock transaction. In the acquisition, we assumed Concho’s publicly traded debt. On December 7, 2020, we launched an offer to exchange Concho’s publicly traded debt for debt issued by ConocoPhillips. The exchange offer settled on February 8, 2021. Of the approximately $3.9 billion in aggregate principal amount of Concho’s notes subject to the exchange offer, 98 percent, or approximately $3.8 billion, was tendered and exchanged for new debt issued by ConocoPhillips. There were no impacts to ConocoPhillips’ credit ratings as a result of the debt exchange. For additional information, see Note 10—Debt and Note 25—Acquisition of Concho Resources Inc., in the Notes to Consolidated Financial Statements.

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

**Guarantor Summarized Financial Information**

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and Burlington 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.

In March of 2020, the SEC adopted amendments to simplify the financial disclosure requirements for guarantors and issuers of guaranteed securities registered under Rule 3-10 of Regulation S-X. Based on our evaluation of our existing guarantee relationships, we qualify for the transition to alternative disclosures. We elected early voluntary compliance with the final amendments beginning in the third quarter of 2020. Accordingly, condensed consolidating information by guarantor and issuer of guaranteed securities will no longer be reported, and alternative disclosures of summarized financial information for the consolidated Obligor Group is presented. The following tables present summarized financial information for the Obligor Group, as defined below:

- The Obligor Group will reflect guarantors and issuers of guaranteed securities consisting of ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC.
- Consolidating adjustments for elimination of investments in and transactions between the collective guarantors and issuers of guaranteed securities are reflected in the balances of the summarized financial information.

- Non-Obligated Subsidiaries are excluded from this presentation.

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

**Summarized Income Statement Data**

| | | Millions of Dollars<br>**2020** |
|---|---|---|
| Revenues and Other Income | $ | **8,375** |
| Income (loss) before income taxes | | **(2,999)** |
| Net income (loss) | | **(2,701)** |
| Net Income (Loss) Attributable to ConocoPhillips | | **(2,701)** |

**Summarized Balance Sheet Data**

| | | Millions of Dollars<br>**December 31, 2020** |
|---|---|---|
| Current assets | $ | **8,535** |
| *Amounts due from Non-Obligated Subsidiaries, current* | | **440** |
| Noncurrent assets | | **37,180** |
| *Amounts due from Non-Obligated Subsidiaries, noncurrent* | | **7,730** |
| Current liabilities | | **3,797** |
| *Amounts due to Non-Obligated Subsidiaries, current* | | **1,365** |
| Noncurrent liabilities | | **18,627** |
| *Amounts due to Non-Obligated Subsidiaries, noncurrent* | | **3,972** |

**Capital Requirements**

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

Our debt balance at December 31, 2020, was $15,369 million, an increase of $474 million from the balance at December 31, 2019. Maturities of debt (including payments for finance leases) due in 2021 of $601 million, excluding net unamortized premiums and discounts, will be paid from current cash balances and cash generated by operations. For more information on Debt, see Note 10—Debt, in the Notes to Consolidated Financial Statements.

We believe in delivering value to our shareholders via a growing and sustainable dividend supplemented by additional returns of capital, including share repurchases. In 2020, we paid $1,831 million, $1.69 per share of common stock, in dividends. This is an increase over 2019 and 2018, when we paid $1.34 and $1.16 per share of common stock, respectively. In February 2021, we announced a quarterly dividend of $0.43 per share, payable March 1, 2021, to stockholders of record at the close of business on February 12, 2021.

In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. Cost of share repurchases were $892 million, $3,500 million and $2,999 million in 2020, 2019 and 2018, respectively. Share repurchases since inception of our current program totaled 189 million shares at a cost of $10,517 million, as of December 31, 2020. In the fourth quarter of 2020, we suspended share repurchases upon entry into a definitive agreement to acquire Concho. We resumed share repurchases in February 2021 after the completion of our Concho acquisition. Repurchases are made at management’s discretion, at prevailing prices, subject to market conditions and other factors.

Our dividend and share repurchase programs are subject to numerous considerations, including market conditions, management discretion and other factors. See “Item 1A—Risk Factors – Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.”

In addition to the requirements above, we have contractual obligations for the purchase of goods and services of approximately $8,123 million. We expect to fulfill $2,805 million of these obligations in 2021. These figures exclude purchase commitments for jointly owned fields and facilities where we are not the operator. Purchase obligations of $5,237 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG product terminals, to transport, process, treat and store commodities. Purchase obligations of $2,290 million are related to market-based contracts for commodity product purchases with third parties. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

**Capital Expenditures and Investments**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Alaska | $ **1,038** | 1,513 | 1,298 |
| Lower 48 | **1,881** | 3,394 | 3,184 |
| Canada | **651** | 368 | 477 |
| Europe, Middle East and North Africa | **600** | 708 | 877 |
| Asia Pacific | **384** | 584 | 718 |
| Other International | **121** | 8 | 6 |
| Corporate and Other | **40** | 61 | 190 |
| Capital Program | $ **4,715** | 6,636 | 6,750 |

Our capital expenditures and investments for the three-year period ended December 31, 2020 totaled $18.1 billion. The 2020 expenditures supported key exploration and developments, primarily:

- Development and appraisal in the Lower 48, including Eagle Ford, Permian, and Bakken.
- Appraisal and development activities in Alaska related to the Western North Slope; development activities in the Greater Kuparuk Area and the Greater Prudhoe Area.
- Development and exploration activities across assets in Norway.
- Appraisal activities in liquids-rich plays and optimization of oil sands development in Canada.
- Continued development activities in China, Malaysia, and Indonesia.
- Exploration activities in Argentina.

2021 CAPITAL BUDGET

In February 2021, we announced 2021 operating plan capital for the combined company of $5.5 billion. The plan includes $5.1 billion to sustain current production and $0.4 billion for investment in major projects, primarily in Alaska, in addition to ongoing exploration appraisal activity.

The operating plan capital budget of $5.5 billion is expected to deliver production from the combined company of approximately 1.5 MMBOED in 2021. This production guidance excludes Libya.

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

**Contingencies**

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the 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.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

*Legal and Tax Matters*

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

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 18—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income tax-related contingencies.

*Environmental*

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

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

- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

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

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

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

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

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

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2020, there were 15 sites around the U.S. in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a 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 $393 million in 2020 and are expected to be about $435 million per year in 2021 and 2022. Capitalized environmental costs were $161 million in 2020 and are expected to be about $210 million per year in 2021 and 2022.

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

Many of these liabilities result from CERCLA, RCRA and similar state or international laws that require us 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, 2020, our balance sheet included total accrued environmental costs of $180 million, compared with $171 million at December 31, 2019, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

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

*Climate Change*

Continuing political and social attention to the issue of global climate change has resulted in a broad range 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 2020 was approximately $7 million 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 2020 was approximately $2 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA , 549 U.S. 497, 127 S.Ct. 1438 (2007), confirmed that the EPA has the authority to regulate carbon dioxide as an “air pollutant” under the Federal Clean Air Act.
- The U.S. EPA’s announcement on March 29, 2010 (published as “Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs,” 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA’s and U.S. Department of Transportation’s joint promulgation of a Final Rule 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 established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2020 was approximately $29 million (net share before-tax). We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia and Alberta operations in Canada, totaling approximately $3.5 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the 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.

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.

*Climate Change Litigation*
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 any potential financial impact on the company.

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

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

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

Emissions are categorized into three different scopes. Gross operated Scope 1 and Scope 2 GHG emissions help us understand our climate transition risk.

- Scope 1 emissions are direct GHG emissions from sources that we own or control.
- Scope 2 emissions are GHG emissions from the generation of purchased electricity or steam that 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. We have set a target to reduce our gross operated (scope 1 and 2) emissions intensity by 35 to 45 percent from 2016 levels by 2030, with an ambition to achieve net-zero operated emissions by 2050. We have joined the World Bank Flaring Initiative to work towards zero routine flaring of gas by 2030.
- Technology choices: We expanded our Marginal Abatement Cost Curve process to provide a broader range of opportunities for emission reduction technology.
- Portfolio choices: Our corporate authorization process requires all qualifying projects to include a GHG price in their project approval economics. Different GHG prices are used depending on the region or jurisdiction. Projects in jurisdictions with existing GHG pricing regimes incorporate the existing GHG price and forecast into their economics. Projects where no existing GHG pricing regime exists utilize a scenario forecast from our internally consistent World Energy Model. In this way, both existing and emerging regulatory requirements are considered in our decision-making. The company does not use an estimated market cost of GHG emissions when assessing reserves in jurisdictions without existing GHG regulations.
- External engagement: Our external engagement aims to differentiate ConocoPhillips within the oil 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—Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussion of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

### Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of 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.

*Property Acquisition Costs*

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

At year-end 2020, the remaining $2.4 billion of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $1.9 billion is concentrated in 10 major development areas, the majority of which are not expected to move to proved properties in 2021. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

*Exploratory Costs*

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

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

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

At year-end 2020, total suspended well costs were $682 million, compared with $1,020 million at year-end 2019. For additional information on suspended wells, including an aging analysis, see Note 7—Suspended Wells and Exploration Expenses, in the Notes to Consolidated Financial Statements.

*Proved Reserves*

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

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

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will 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 developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2020, the net book value of productive PP&E subject to a unit-of-production calculation was approximately $33 billion and the DD&A recorded on these assets in 2020 was approximately $5.3 billion. The estimated proved developed reserves for our consolidated operations were 3.2 billion BOE at the end of 2019 and 2.5 billion BOE at the end of 2020. 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 2020 would have increased by an estimated $588 million.

**Impairments**

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in 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, upon review, the sum of the undiscounted cash flows before income-taxes is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as impairments 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 information at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. See Note 8—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are 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 5—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

**Asset Retirement Obligations and Environmental Costs**

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. 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 9—Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

**Projected Benefit Obligations**

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 100 basis-point decrease in the discount rate assumption would increase projected benefit obligations by $1,200 million. Benefit expense is sensitive to the discount rate and return on plan assets assumptions. A 100 basis-point decrease in the discount rate assumption would increase annual benefit expense by $110 million, while a 100 basis-point decrease in the return on plan assets assumption would increase annual benefit expense by $80 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 17—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

**Contingencies**

A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages, and underpayments associated with environmental remediation, tax, contracts, and other legal disputes. As we learn new facts concerning contingencies, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure. However, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration, or other third-party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties. Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For additional information on contingent liabilities, see the “Contingencies” section within “Capital Resources and Liquidity” and Note 12—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

**Income Taxes**

We are subject to income taxation in numerous jurisdictions worldwide. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess our deferred tax assets and reduce such assets 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 18—Income Taxes for additional information, in the Notes to Consolidated Financial Statements.

We regularly assess and, if required, establish accruals for uncertain tax positions that could result from assessments of additional tax by taxing jurisdictions in countries where we operate. We recognize a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. These accruals for uncertain tax positions are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, court proceedings, changes in applicable tax laws, including tax case rulings and legislative guidance, or expiration of the applicable statute of limitations. See Note 18—Income Taxes for additional information, in the Notes to Consolidated Financial Statements.

**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, the anticipated benefits of the transaction between us and Concho, the anticipated impact of the transaction on the combined company's business and future financial and operating results, the expected amount and the timing of synergies from the transaction are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by the words "anticipate," "believe," "budget," "continue," "could," "effort," "estimate," "expect," "forecast," "intend," "goal," "guidance," "may," "objective," "outlook," "plan," "potential," "predict," "projection," "seek," "should," "target," "will," "would" and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to 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.
- 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, 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 the potential for litigation related to the transaction with Concho, or our failure to comply with applicable laws and regulations.
- General domestic and international economic and political developments, including armed 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.
- Our inability to liquidate the common stock issued to us by Cenovus Energy as part of our sale of certain assets in western Canada at prices we deem acceptable, or at all.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us, including our ability to collect payments when due from the government of Venezuela or PDVSA.
- Our inability to realize anticipated cost savings and capital expenditure reductions.
- The inadequacy of storage capacity for our products, and ensuing curtailments, whether voluntary or involuntary, required to mitigate this physical constraint.
- Our ability to successfully integrate Concho's business.
- The risk that the expected benefits and cost reductions associated with the transaction with Concho may not be fully achieved in a timely manner, or at all.
- The risk that we will be unable to retain and hire key personnel.
- Unanticipated difficulties or expenditures relating to integration with Concho.
- Uncertainty as to the long-term value of our common stock.
- The diversion of management time on integration-related matters.
- The factors generally described in Item 1A—Risk Factors in this 2020 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

## Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose 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, 2020, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2020 and 2019, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

*Interest Rate Risk*
The following table provides information about our debt instruments that are sensitive to changes in U.S. interest rates. The table presents principal cash flows and related weighted-average interest rates by 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 cashflows associated with fixed rate debt, unless we elect to repurchase or retire such debt prior to maturity.

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

*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, 2020 and 2019, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps for purposes of mitigating our cash-related exposures. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we 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, 2020, we had outstanding foreign currency exchange forward contracts to sell $0.45 billion CAD at $0.748 CAD against the U.S. dollar. At December 31, 2019, we had outstanding foreign currency exchange forward contracts to sell $1.35 billion CAD at $0.748 CAD against the U.S. dollar. Based on the assumed volatility in the fair value calculation, the net fair value of these foreign currency contracts at December 31, 2020 and December 31, 2019, were a before-tax loss of $16 million and $28 million, respectively. Based on an adverse hypothetical 10 percent change in the December 2020 and December 2019 exchange rate, this would result in an additional before-tax loss of $39 million and $115 million, respectively. The sensitivity analysis is based on changing one assumption while holding all other assumptions constant, which in practice may be unlikely to occur, as changes in some of the assumptions may be correlated.

The gross notional and fair value of these positions at December 31, 2020 and 2019, were as follows:

| | | In Millions | | | |
|---|---|---|---|---|---|
| **Foreign Currency Exchange Derivatives** | | Notional | | Fair Value* | |
| | | **2020** | 2019 | **2020** | 2019 |
| Sell Canadian dollar, buy U.S. dollar | CAD | **450** | 1,350 | **(16)** | (28) |
| Buy Canadian dollar, sell U.S. dollar | CAD | **80** | 13 | **2** | - |
| Sell British pound, buy euro | GBP | **8** | - | - | - |
| Buy British pound, sell euro | GBP | **3** | 4 | - | - |

**Denominated in USD.*

For additional information about our use of derivative instruments, see Note 13—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

**Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

**CONOCOPHILLIPS**

**INDEX TO FINANCIAL STATEMENTS**

## Reports of Management

Management prepared, and is responsible for, the consolidated financial statements and the other 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, 2020. 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, 2020.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2020, 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, 2020 and 2019, the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with U.S. generally 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, 2020, 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 16, 2021, expressed an unqualified opinion thereon.

### Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities 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, 2020, the asset retirement obligation (ARO) balance totaled $5.6 billion. As further described in Note 9, the Company records AROs in the period in which they are incurred, typically when the asset is installed at the production location. The estimation of certain obligations related to deepwater offshore assets requires significant judgment given the magnitude of these removal costs and higher estimation uncertainty related to the removal plan and costs. Furthermore, given certain of these assets are nearing the end of their operations, the impact of changes in these AROs may result in a material impact to earnings given the relatively short remaining useful lives of the assets.

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

*How We Addressed the Matter in Our Audit*

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

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

***Depreciation, depletion and amortization and impairment of properties, plants and equipment***

*Description of the Matter*

At December 31, 2020, the net book value of the Company's properties, plants and equipment (PP&E) was $39.9 billion, and depreciation, depletion and amortization (DD&A) expense and impairment expense were $5.5 billion and $0.8 billion, respectively, for the year then ended. As described in Note 1, under the successful efforts method of accounting, DD&A of PP&E on producing hydrocarbon properties 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. PP&E used in operations is assessed by management for impairment when changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If there is an indication the carrying value of an asset may not be recovered, the Company compares undiscounted cash flows before income taxes to the carrying value of the asset group. If the expected undiscounted cash flows before income taxes are lower than the carrying value of the asset group, the carrying value is written down to estimated fair value.

Proved oil and gas reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. Additionally, the expected future cash flows used for impairment reviews and related fair value calculations are based on future production volumes of estimated oil and gas reserves. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and gas reserves, management also used 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 and impairment calculations 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 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 and impairments, including management's controls over the completeness and accuracy of the financial data provided to the internal reservoir engineers for use in estimating oil and gas reserves.

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

/s/ Ernst & Young LLP

We have served as ConocoPhillips' auditor since 1949.

Houston, Texas
February 16, 2021

**Report of Independent Registered Public Accounting Firm**

To the Stockholders and the Board of Directors of ConocoPhillips

**Opinion on Internal Control over Financial Reporting**

We have audited ConocoPhillips' internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring 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, 2020, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2020, and the related notes and our report dated February 16, 2021, expressed an unqualified opinion thereon.

**Basis for Opinion**

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Reports of Management." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our 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 16, 2021

| **Consolidated Income Statement** | | | | **ConocoPhillips** |
|---|---|---|---|---|

| Years Ended December 31 | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| **Revenues and Other Income** | | | | |
| Sales and other operating revenues | $ | **18,784** | 32,567 | 36,417 |
| Equity in earnings of affiliates | | **432** | 779 | 1,074 |
| Gain on dispositions | | **549** | 1,966 | 1,063 |
| Other income (loss) | | **(509)** | 1,358 | 173 |
| Total Revenues and Other Income | | **19,256** | 36,670 | 38,727 |
| **Costs and Expenses** | | | | |
| Purchased commodities | | **8,078** | 11,842 | 14,294 |
| Production and operating expenses | | **4,344** | 5,322 | 5,213 |
| Selling, general and administrative expenses | | **430** | 556 | 401 |
| Exploration expenses | | **1,457** | 743 | 369 |
| Depreciation, depletion and amortization | | **5,521** | 6,090 | 5,956 |
| Impairments | | **813** | 405 | 27 |
| Taxes other than income taxes | | **754** | 953 | 1,048 |
| Accretion on discounted liabilities | | **252** | 326 | 353 |
| Interest and debt expense | | **806** | 778 | 735 |
| Foreign currency transaction (gains) losses | | **(72)** | 66 | (17) |
| Other expenses | | **13** | 65 | 375 |
| Total Costs and Expenses | | **22,396** | 27,146 | 28,754 |
| Income (loss) before income taxes | | **(3,140)** | 9,524 | 9,973 |
| Income tax provision (benefit) | | **(485)** | 2,267 | 3,668 |
| Net income (loss) | | **(2,655)** | 7,257 | 6,305 |
| Less: net income attributable to noncontrolling interests | | **(46)** | (68) | (48) |
| **Net Income (Loss) Attributable to ConocoPhillips** | **$** | **(2,701)** | 7,189 | 6,257 |
| **Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock** *(dollars)* | | | | |
| Basic | **$** | **(2.51)** | 6.43 | 5.36 |
| Diluted | | **(2.51)** | 6.40 | 5.32 |
| **Average Common Shares Outstanding** *(in thousands)* | | | | |
| Basic | | **1,078,030** | 1,117,260 | 1,166,499 |
| Diluted | | **1,078,030** | 1,123,536 | 1,175,538 |

*See Notes to Consolidated Financial Statements.*

**Consolidated Statement of Comprehensive Income** **ConocoPhillips**

| Years Ended December 31 | | Millions of Dollars | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Net Income (Loss)** | $ **(2,655)** | 7,257 | 6,305 |
| Other comprehensive income (loss) | | | |
| Defined benefit plans | | | |
| Prior service credit (cost) arising during the period | **29** | - | (7) |
| Reclassification adjustment for amortization of prior service credit included in net income (loss) | **(32)** | (35) | (40) |
| Net change | **(3)** | (35) | (47) |
| Net actuarial loss arising during the period | **(210)** | (55) | (150) |
| Reclassification adjustment for amortization of net actuarial losses included in net income (loss) | **117** | 146 | 279 |
| Net change | **(93)** | 91 | 129 |
| Nonsponsored plans* | **1** | (3) | (1) |
| Income taxes on defined benefit plans | **20** | (2) | (42) |
| Defined benefit plans, net of tax | **(75)** | 51 | 39 |
| Unrealized holding gain on securities | **2** | - | - |
| Unrealized gain on securities, net of tax | **2** | - | - |
| Foreign currency translation adjustments | **209** | 699 | (645) |
| Income taxes on foreign currency translation adjustments | **3** | (4) | 3 |
| Foreign currency translation adjustments, net of tax | **212** | 695 | (642) |
| **Other Comprehensive Income (Loss), Net of Tax** | **139** | 746 | (603) |
| **Comprehensive Income (Loss)** | **(2,516)** | 8,003 | 5,702 |
| Less: comprehensive income attributable to noncontrolling interests | **(46)** | (68) | (48) |
| **Comprehensive Income (Loss) Attributable to ConocoPhillips** | $ **(2,562)** | 7,935 | 5,654 |

**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 | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Assets** | | | |
| Cash and cash equivalents | $ | **2,991** | 5,088 |
| Short-term investments | | **3,609** | 3,028 |
| Accounts and notes receivable (net of allowance of $4 and $13, respectively) | | **2,634** | 3,267 |
| Accounts and notes receivable—related parties | | **120** | 134 |
| Investment in Cenovus Energy | | **1,256** | 2,111 |
| Inventories | | **1,002** | 1,026 |
| Prepaid expenses and other current assets | | **454** | 2,259 |
| Total Current Assets | | **12,066** | 16,913 |
| Investments and long-term receivables | | **8,017** | 8,687 |
| Loans and advances—related parties | | **114** | 219 |
| Net properties, plants and equipment | | | |
| (net of accumulated DD&A of $62,213 and $55,477, respectively) | | **39,893** | 42,269 |
| Other assets | | **2,528** | 2,426 |
| Total Assets | $ | **62,618** | 70,514 |
| | | | |
| **Liabilities** | | | |
| Accounts payable | $ | **2,669** | 3,176 |
| Accounts payable—related parties | | **29** | 24 |
| Short-term debt | | **619** | 105 |
| Accrued income and other taxes | | **320** | 1,030 |
| Employee benefit obligations | | **608** | 663 |
| Other accruals | | **1,121** | 2,045 |
| Total Current Liabilities | | **5,366** | 7,043 |
| Long-term debt | | **14,750** | 14,790 |
| Asset retirement obligations and accrued environmental costs | | **5,430** | 5,352 |
| Deferred income taxes | | **3,747** | 4,634 |
| Employee benefit obligations | | **1,697** | 1,781 |
| Other liabilities and deferred credits | | **1,779** | 1,864 |
| Total Liabilities | | **32,769** | 35,464 |
| | | | |
| **Equity** | | | |
| Common stock (2,500,000,000 shares authorized at $0.01 par value) | | | |
| Issued (2020—1,798,844,267 shares; 2019—1,795,652,203 shares) | | | |
| Par value | | **18** | 18 |
| Capital in excess of par | | **47,133** | 46,983 |
| Treasury stock (at cost: 2020—730,802,089 shares; 2019—710,783,814 shares) | | **(47,297)** | (46,405) |
| Accumulated other comprehensive loss | | **(5,218)** | (5,357) |
| Retained earnings | | **35,213** | 39,742 |
| Total Common Stockholders' Equity | | **29,849** | 34,981 |
| Noncontrolling interests | | **-** | 69 |
| Total Equity | | **29,849** | 35,050 |
| Total Liabilities and Equity | $ | **62,618** | 70,514 |

*See Notes to Consolidated Financial Statements.*

**Consolidated Statement of Cash Flows** **ConocoPhillips**

| Years Ended December 31 | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Cash Flows From Operating Activities** | | | |
| Net income (loss) | $ **(2,655)** | 7,257 | 6,305 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities | | | |
| Depreciation, depletion and amortization | **5,521** | 6,090 | 5,956 |
| Impairments | **813** | 405 | 27 |
| Dry hole costs and leasehold impairments | **1,083** | 421 | 95 |
| Accretion on discounted liabilities | **252** | 326 | 353 |
| Deferred taxes | **(834)** | (444) | 283 |
| Undistributed equity earnings | **645** | 594 | 152 |
| Gain on dispositions | **(549)** | (1,966) | (1,063) |
| Unrealized (gain) loss on investment in Cenovus Energy | **855** | (649) | 437 |
| Other | **43** | (351) | (246) |
| Working capital adjustments | | | |
| Decrease in accounts and notes receivable | **521** | 505 | 235 |
| Decrease (increase) in inventories | **(25)** | (67) | 86 |
| Decrease (increase) in prepaid expenses and other current assets | **76** | 37 | (55) |
| Decrease in accounts payable | **(249)** | (378) | (52) |
| Increase (decrease) in taxes and other accruals | **(695)** | (676) | 421 |
| Net Cash Provided by Operating Activities | **4,802** | 11,104 | 12,934 |
| | | | |
| **Cash Flows From Investing Activities** | | | |
| Capital expenditures and investments | **(4,715)** | (6,636) | (6,750) |
| Working capital changes associated with investing activities | **(155)** | (103) | (68) |
| Proceeds from asset dispositions | **1,317** | 3,012 | 1,082 |
| Net sales (purchases) of investments | **(658)** | (2,910) | 1,620 |
| Collection of advances/loans—related parties | **116** | 127 | 119 |
| Other | **(26)** | (108) | 154 |
| Net Cash Used in Investing Activities | **(4,121)** | (6,618) | (3,843) |
| | | | |
| **Cash Flows From Financing Activities** | | | |
| Issuance of debt | **300** | - | - |
| Repayment of debt | **(254)** | (80) | (4,995) |
| Issuance of company common stock | **(5)** | (30) | 121 |
| Repurchase of company common stock | **(892)** | (3,500) | (2,999) |
| Dividends paid | **(1,831)** | (1,500) | (1,363) |
| Other | **(26)** | (119) | (123) |
| Net Cash Used in Financing Activities | **(2,708)** | (5,229) | (9,359) |
| | | | |
| **Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash** | **(20)** | (46) | (117) |
| | | | |
| **Net Change in Cash, Cash Equivalents and Restricted Cash** | **(2,047)** | (789) | (385) |
| Cash, cash equivalents and restricted cash at beginning of period | **5,362** | 6,151 | 6,536 |
| Cash, Cash Equivalents and Restricted Cash at End of Period | $ **3,315** | 5,362 | 6,151 |

*Restricted cash of $94 million and $230 million is included in the "Prepaid expenses and other current assets" and "Other assets" lines, respectively, of our Consolidated Balance Sheet as of December 31, 2020.*
*Restricted cash of $90 million and $184 million is included in the "Prepaid expenses and other current assets" and "Other assets" lines, respectively, of our Consolidated Balance Sheet as of December 31, 2019.*
*See Notes to Consolidated Financial Statements.*

| | 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, 2017 | $ 18 | 46,622 | (39,906) | (5,518) | 29,391 | 194 | 30,801 |
| Net income | | | | | 6,257 | 48 | 6,305 |
| Other comprehensive loss | | | | (603) | | | (603) |
| Dividends paid ($1.16 per share of common stock) | | | | | (1,363) | | (1,363) |
| Repurchase of company common stock | | | (2,999) | | | | (2,999) |
| Distributions to noncontrolling interests and other | | | | | | (121) | (121) |
| Distributed under benefit plans | | 257 | | | | | 257 |
| Changes in Accounting Principles* | | | | 58 | (278) | | (220) |
| Other | | | | | 3 | 4 | 7 |
| 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 income | | | | 746 | | | 746 |
| Dividends paid ($1.34 per share of common stock) | | | | | (1,500) | | (1,500) |
| Repurchase of company common stock | | | (3,500) | | | | (3,500) |
| Distributions to noncontrolling interests and other | | | | | | (128) | (128) |
| Distributed under benefit plans | | 104 | | | | | 104 |
| Changes in Accounting Principles** | | | | (40) | 40 | | - |
| Other | | | | | 3 | 4 | 7 |
| 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 paid ($1.69 per share of common stock) | | | | | **(1,831)** | | **(1,831)** |
| Repurchase of company common stock | | | **(892)** | | | | **(892)** |
| Distributions to noncontrolling interests and other | | | | | | **(32)** | **(32)** |
| Disposition | | | | | | **(84)** | **(84)** |
| Distributed under benefit plans | | **150** | | | | | **150** |
| Other | | | | | **3** | **1** | **4** |
| **Balances at December 31, 2020** | **$ 18** | **47,133** | **(47,297)** | **(5,218)** | **35,213** | **-** | **29,849** |

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

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

*See Notes to Consolidated Financial Statements.*

## Note 1—Accounting Policies

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

  We manage our operations through six operating segments, defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. For additional information, see Note 24—Segment Disclosures and Related Information.

  The unrealized (gain) loss on investment in Cenovus Energy included on our consolidated statement of cash flows, previously reflected on the line item "Other" within net cash provided by operating activities, has been reclassified in the comparative periods to conform with the current period's presentation.

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

- **Use of Estimates**—The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets 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 on our derivative instruments.

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

  **Property Acquisition Costs**—Oil and gas leasehold acquisition costs are capitalized and included 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 7—Suspended Wells and Exploration Expenses, for additional information on suspended wells.

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

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

- **Capitalized Interest**—Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the 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**—PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If there is an indication the carrying amount of an asset may not be recovered, a recoverability test is performed using management's assumptions such as for prices, volumes and future development plans. If, upon review, the sum of the undiscounted cash flows before income-taxes is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment in the period in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of 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. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

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

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

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

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

- **Asset Retirement Obligations and Environmental Costs**—The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). Fair value is estimated using a present value approach, incorporating assumptions about estimated amounts and timing of settlements and impacts of the use of technologies. When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. Reductions to estimated liabilities for assets that are no longer producing are recorded as a credit to impairment, if the asset had been previously impaired, or as a credit to DD&A, if the asset had not been previously impaired. For additional information, see Note 9—Asset Retirement Obligations and Accrued Environmental Costs.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired 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.

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

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

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

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

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

## Note 2—Changes in Accounting Principles

We adopted the provisions of FASB ASU No. 2016-13, "Measurement of Credit Losses on Financial Instruments," (ASC Topic 326) and its amendments, beginning January 1, 2020. This ASU, as amended, sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments measured at amortized cost basis based on expected losses rather than incurred losses. This ASU, as amended, which primarily applies to our accounts receivable, also requires credit losses related to available-for-sale debt securities to be recorded through an allowance for credit losses. The adoption of this ASU did not have a material impact to our financial statements. The majority of our receivables are due within 30 days or less. We monitor the credit quality of our counterparties through review of collections, credit ratings, and other analyses. We develop our estimated allowance for credit losses primarily using an aging method and analyses of historical loss rates as well as consideration of current and future conditions that could impact our counterparties' credit quality and liquidity.

**Note 3—Inventories**

Inventories at December 31 were:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| Crude oil and natural gas | $ | **461** | 472 |
| Materials and supplies | | **541** | 554 |
| | $ | **1,002** | 1,026 |

Inventories valued on the LIFO basis totaled $282 million and $286 million at December 31, 2020 and 2019, respectively. In the first quarter of 2020, we recorded a lower of cost or market adjustment of $228 million to our crude oil and natural gas inventories, which is included in the “Purchased commodities” line on our consolidated income statement. Commodity prices have since improved. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $87 million and $155 million at December 31, 2020 and 2019, respectively.

**Note 4—Asset Acquisitions and Dispositions**

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

On January 15, 2021, we completed our acquisition of Concho Resources Inc. (Concho), an independent oil and gas exploration and production company with operations across New Mexico and West Texas focused in the Permian Basin. Total consideration for the all-stock transaction was valued at $13.1 billion, in which 1.46 shares of ConocoPhillips common stock was exchanged for each outstanding share of Concho common stock, resulting in the issuance of approximately 286 million shares of ConocoPhillips common stock. We also assumed $3.9 billion in aggregate principal amount of outstanding debt for Concho, which was recorded at fair value of $4.7 billion as of the closing date. For additional information related to this transaction, see Note 25—Acquisition of Concho Resources Inc.

*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. The before-tax earnings associated with our interests in Niobrara for the year ended December 31, 2018 was $35 million. Results of operations for the Niobrara interests sold were reported in our Lower 48 segment.

In May 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations, and based on an effective date of January 1, 2019, we received proceeds of $765 million with an additional $200 million due upon final investment decision of the proposed Barossa development project. 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, $372 million and $364 million for the years ended December 31, 2020, 2019 and 2018, respectively. Production from the beginning of the year through the disposition date in May 2020 averaged 43 MBOED. Results of operations for the subsidiaries sold were reported in our Asia Pacific segment.

_2019_

**Assets Sold**

In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in the Golden Pass LNG Terminal and Golden Pass Pipeline. We also entered into agreements to amend our contractual obligations for retaining use of the facilities. As a result of entering into these agreements, we recorded a before-tax impairment of $60 million in the first quarter of 2019 which is included in the “Equity in earnings of affiliates” line on our consolidated income statement. We completed the sale in the second quarter of 2019. Results of operations for these assets were reported in our Lower 48 segment. See Note 14—Fair Value Measurement for additional information.

In April 2019, we entered into an agreement to sell two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited for $2.675 billion plus interest and customary adjustments, with an effective date of January 1, 2018. On September 30, 2019, we completed the sale for proceeds of $2.2 billion and recognized a $1.7 billion before-tax and $2.1 billion after-tax gain associated with this transaction in 2019. Together the subsidiaries sold indirectly held 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, were $2.1 billion and $0.9 billion for the years ended December 31, 2019 and 2018, respectively. Results of operations for the U.K. were reported within our Europe, Middle East and North Africa segment.

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

In the fourth quarter of 2019, we sold our interests in the Magnolia field and platform for net proceeds of $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.

*2018*

**Assets Sold**

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

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

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

**Acquisitions**

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

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

## Note 5—Investments, Loans and Long-Term Receivables

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| Equity investments | $ | **7,596** | 8,234 |
| Loans and advances—related parties | | **114** | 219 |
| Long-term receivables | | **137** | 243 |
| Long-term investments in debt securities | | **217** | 133 |
| Other investments | | **67** | 77 |
| | $ | **8,131** | 8,906 |

**Equity Investments**
Affiliated companies in which we had a significant equity investment at December 31, 2020, included:

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

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

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| Revenues | $ | **7,931** | 11,310 | 11,654 |
| Income before income taxes | | **1,843** | 3,726 | 3,660 |
| Net income | | **1,426** | 3,085 | 3,244 |

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| Current assets | $ | **2,579** | 3,289 |
| Noncurrent assets | | **35,257** | 38,905 |
| Current liabilities | | **2,110** | 2,603 |
| Noncurrent liabilities | | **18,099** | 22,168 |

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

At December 31, 2020, retained earnings included $41 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,076 million, $1,378 million and $1,226 million in 2020, 2019 and 2018, respectively.

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

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

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

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

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

At December 31, 2020, a balance of $6.2 billion was outstanding on the facilities. See Note 11—Guarantees, for additional information.

During the fourth quarter of 2020, the estimated fair value of our investment in APLNG declined to an amount below carrying value, primarily due to the weakening of the U.S. dollar relative to the Australian dollar. Based on a review of the facts and circumstances surrounding this decline in fair value, we concluded the impairment was not other than temporary under the guidance of FASB ASC Topic 323, "Investments – Equity Method and Joint Ventures." In reaching this conclusion, we primarily considered: (1) the volatility and uncertainty in commodity and exchange rate markets; (2) the intent and ability of ConocoPhillips to retain our investment in APLNG; and (3) the short length of time and extent to which fair value has been less than carrying value (fair value exceeded carrying value as of September 30, 2020). Fair value has been estimated based on an internal discounted cash flow model using the following estimated assumptions: estimated future production, an outlook of future prices from a combination of exchanges (short-term) coupled with pricing service companies and our internal outlook (long-term), operating and capital expenditures, a market outlook of foreign exchange rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants.

At December 31, 2020, the fair value of our investment in APLNG was estimated to be $6,560 million, resulting in a not other than temporary impairment of $112 million. We will continue to monitor the relationship between the carrying value and fair value of APLNG. Should we determine in the future there has been a loss in the value of our investment that is other than temporary, we would record an impairment of our equity investment, calculated as the total difference between carrying value and fair value as of the end of the reporting period.

At December 31, 2020, the carrying value of our equity method investment in APLNG was $6,672 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $6,242 million, resulting in a basis difference of $430 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income (loss) attributable to ConocoPhillips for 2020, 2019 and 2018 was after-tax expense of $41 million, $36 million and $44 million, respectively, representing the amortization of this basis difference on currently producing licenses.

**QG3**

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $220 million as described below under "Loans and Long-Term Receivables." At December 31, 2020, the book value of our equity method investment in QG3, excluding the project financing, was $742 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. We previously held a 12.4 percent interest in Golden Pass LNG Terminal and Golden Pass Pipeline, but we sold those interests in the second quarter of 2019 while retaining the basic use agreements. Currently, the LNG from QG3 is being sold to markets outside of the U.S. For additional information, see Note 4—Asset Acquisitions and Dispositions.

**Loans and Long-Term Receivables**

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

At December 31, 2020, significant loans to affiliated companies include $220 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

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

**Note 6—Investment in Cenovus Energy**

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

At December 31, 2020, the investment included on our consolidated balance sheet was $1.26 billion and is carried at fair value. The fair value of the 208 million Cenovus Energy common shares reflects the closing price of $6.04 per share on the NYSE on the last trading day of the quarter, a decrease of $855 million from its fair value of $2.11 billion at December 31, 2019. The decrease in fair value resulted in a net unrealized loss recorded within the "Other income (loss)" line of our consolidated income statement for the year ended December 31, 2020 relating to the shares held at the reporting date. For the years ended 2019 and 2018, we recorded an unrealized gain of $649 million and an unrealized loss of $437 million, respectively. See Note 14—Fair Value Measurement and Note 21—Other Financial Information, for additional information. Subject to market conditions, we intend to decrease our investment over time through market transactions, private agreements or otherwise.

On January 4, 2021, Cenovus Energy completed its all-stock acquisition of Husky Energy Inc. As a result of this transaction, our investment now approximates 10 percent of the issued and outstanding Cenovus Energy common stock.

**Note 7—Suspended Wells and Exploration Expenses**

The following table reflects the net changes in suspended exploratory well costs during 2020, 2019 and 2018:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Beginning balance at January 1 | $ **1,020** | 856 | 853 |
| Additions pending the determination of proved reserves | **164** | 239 | 140 |
| Reclassifications to proved properties | **(42)** | (11) | (37) |
| Sales of suspended wells | **(313)** | (54) | (93) |
| Charged to dry hole expense | **(147)** | (10) | (7) |
| Ending balance at December 31 | $ **682** | 1,020 * | 856 |

**Includes $313 million of assets held for sale in Australia at December 31, 2019.*
*For additional details on suspended wells charged to dry hole expense, see the Exploration Expenses section of this Note.*

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

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Exploratory well costs capitalized for a period of one year or less | $ **156** | 206 | 145 |
| Exploratory well costs capitalized for a period greater than one year | **526** | 814 | 711 |
| Ending balance | $ **682** | 1,020 * | 856 |
| Number of projects with exploratory well costs capitalized for a period greater than one year | **22** | 23 | 24 |

**Includes $313 million of assets held for sale in Australia at December 31, 2019.*

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2020:

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | | Suspended Since | | |
| | Total | 2017–2019 | 2014–2016 | 2004–2013 |
| NPRA—Alaska[1] | 240 | 190 | 50 | - |
| Surmont—Canada[1] | 120 | 4 | 31 | 85 |
| Narwhal Trend—Alaska[1] | 52 | 52 | - | - |
| PL782S—Norway[1] | 22 | 22 | - | - |
| WL4-00—Malaysia[1] | 17 | 17 | - | - |
| NC 98—Libya[2] | 13 | - | 9 | 4 |
| Other of $10 million or less each[1][2] | 62 | 26 | 19 | 17 |
| Total | $ 526 | 311 | 109 | 106 |

*(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. In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation, completed preliminary FEED technical work for a potential LNG project which would liquefy and export natural gas from Alaska’s North Slope and deliver it to market. In 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment; however, AGDC decided to continue on its own, focusing primarily on permitting efforts. Currently, AGDC is in the process of seeking new sponsors for the project. Given current market conditions, we no longer believe the project will advance and, there is no current market for the asset.

In our Other International segment, our interests in the Middle Magdalena Basin of Colombia are in force majeure. We have no immediate plans to perform under existing contracts; therefore, in 2020, we recorded a before-tax expense totaling $84 million for dry hole costs of a previously suspended well and an impairment 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 8—Impairments**

During 2020, 2019 and 2018, we recognized the following before-tax impairment charges:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| Alaska | $ | - | - | 20 |
| Lower 48 | | **804** | 402 | 63 |
| Canada | | **3** | 2 | 9 |
| Europe, Middle East and North Africa | | **6** | 1 | (79) |
| Asia Pacific | | - | - | 14 |
| | $ | **813** | 405 | 27 |

*2020*
During 2020, we recorded impairments of $813 million, primarily related to certain non-core assets in the Lower 48. Due to a significant decrease in the outlook for current and long-term natural gas prices in early 2020, we recorded impairments of $523 million, primarily for the Wind River Basin operations area, consisting of developed properties in the Madden Field and the Lost Cabin Gas Plant, in the first quarter of 2020. Additionally, due primarily to changes in development plans solidified in the last quarter of 2020, we recognized additional impairments of $287 million in the Lower 48 during the fourth quarter. See Note 14—Fair Value Measurement, for additional information.

*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 4—Asset Acquisitions and Dispositions, for additional information on this disposition.

*2018*
In Alaska, we recorded impairments of $20 million primarily due to cancelled projects.

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

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

## Note 9—Asset Retirement Obligations and Accrued Environmental Costs

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| Asset retirement obligations | $ | **5,573** | 6,206 |
| Accrued environmental costs | | **180** | 171 |
| Total asset retirement obligations and accrued environmental costs | | **5,753** | 6,377 |
| Asset retirement obligations and accrued environmental costs due within one year* | | **(323)** | (1,025) |
| Long-term asset retirement obligations and accrued environmental costs | $ | **5,430** | 5,352 |

**Classified as a current liability on the balance sheet under "Other accruals." For 2019, $741 million relates to assets which were held for sale as of December 31, 2019, and subsequently sold in 2020. For additional information see Note 4—Asset Acquisitions and Dispositions.*

### Asset Retirement Obligations

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

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

During 2020 and 2019, our overall ARO changed as follows:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| Balance at January 1 | $ | **6,206** | 7,908 |
| Accretion of discount | | **248** | 322 |
| New obligations | | **262** | 155 |
| Changes in estimates of existing obligations | | **(307)** | 50 |
| Spending on existing obligations | | **(116)** | (229) |
| Property dispositions | | **(771)** | (1,920) |
| Foreign currency translation | | **51** | (80) |
| Balance at December 31 | $ | **5,573** | 6,206 |

**Accrued Environmental Costs**

Total accrued environmental costs at December 31, 2020 and 2019, were $180 million and $171 million, respectively.

We had accrued environmental costs of $116 million and $112 million at December 31, 2020 and 2019, respectively, related to remediation activities in the U.S. and Canada. We had also accrued in Corporate and Other $48 million and $47 million of environmental costs associated with sites no longer in operation at December 31, 2020 and 2019, respectively. In addition, $16 million and $12 million were included at both December 31, 2020 and 2019, respectively, where the company has been named a potentially responsible 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 $106 million at December 31, 2020. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $23 million in 2021, $17 million in 2022, $18 million in 2023, $3 million in 2024, $2 million in 2025, and $103 million for all future years after 2025.

**Note 10—Debt**

Long-term debt at December 31 was:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| 9.125% Debentures due 2021 | $ | **123** | 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 |
| 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 |
| 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 |
| Floating rate notes due 2022 at 1.12% – 2.81% during 2020 and 2.81% – 3.58% during 2019 | | **500** | 500 |
| Marine Terminal Revenue Refunding Bonds due 2031 at 0.1% – 7.5% during 2020 and 1.08% – 2.45% during 2019 | | **265** | 265 |
| Industrial Development Bonds due 2035 at 0.11% – 7.5% during 2020 and 1.08% – 2.45% during 2019 | | **18** | 18 |
| Commercial Paper at 0.08% – 0.23% during 2020 | | **300** | |
| Other | | **38** | 17 |
| Debt at face value | | **14,292** | 13,971 |
| Finance leases | | **891** | 720 |
| Net unamortized premiums, discounts and debt issuance costs | | **186** | 204 |
| Total debt | | **15,369** | 14,895 |
| Short-term debt | | **(619)** | (105) |
| Long-term debt | $ | **14,750** | 14,790 |

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2021 through 2025 are: $619 million, $1,001 million, $259 million, $579 million and $465 million, respectively.

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

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in 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 our ability to issue up to $6.0 billion of commercial paper, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. We issued $300 million of commercial paper in the third quarter of 2020, which is included in the short-term debt on our consolidated balance sheet. With $300 million of commercial paper outstanding and no direct borrowings or letters of credit, we had access to $5.7 billion in available borrowing capacity under our revolving credit facility at December 31, 2020. We had no direct borrowings, letters of credit, nor outstanding commercial paper as of December 31, 2019.

At both December 31, 2020 and 2019, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. If they are ever redeemed, we have the ability and intent to refinance on a long-term basis, therefore, the VRDBs are included in the “Long-term debt” line on our consolidated balance sheet.

For information on Finance Leases, see Note 16—Non-Mineral Leases.

On January 15, 2021, we completed the acquisition of Concho in an all-stock transaction. In the acquisition, we assumed Concho’s publicly traded debt, which was recorded at fair value of $4.7 billion on the acquisition date. On December 7, 2020, we launched a debt exchange offer which settled on February 8, 2021. Of the approximately $3.9 billion in aggregate principal amount of Concho’s notes subject to the exchange offer, 98 percent, or approximately $3.8 billion, was tendered and exchanged for new debt issued by ConocoPhillips. The new debt received in the exchange is fully and unconditionally guaranteed by ConocoPhillips Company. In conjunction with the exchange offer, Concho successfully solicited consents to amend each of the indentures governing the Concho notes to eliminate certain covenants, restrictive provisions, events of default and the requirements for certain Concho subsidiaries to make future guarantees. For additional information on the acquisition see Note 25—Acquisition of Concho Resources Inc.

**Note 11—Guarantees**

At December 31, 2020, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as 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, 2020, 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 2020 exchange rates:

- During the third quarter of 2016, we issued a guarantee to facilitate the withdrawal of our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee to be 10 years. Our maximum exposure under this guarantee is approximately $170 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2020, the carrying value of this guarantee is approximately $14 million.

- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 1 to 21 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $770 million ($1.4 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

- We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project's continued development. The guarantees have remaining terms of 16 to 25 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $130 million and would become payable if APLNG does not perform. At December 31, 2020, the carrying value of these guarantees was approximately $7 million.

**Other Guarantees**
We have other guarantees with maximum future potential payment amounts totaling approximately $730 million, which consist primarily of guarantees of the residual value of leased office buildings, 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 six years and would become payable if certain asset values are lower than guaranteed amounts at the end of the lease or contract term, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties. At December 31, 2020, the carrying value of these guarantees was approximately $11 million.

**Indemnifications**
Over the years, we have entered into agreements to sell ownership interests in certain legal entities, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes and environmental liabilities. Most of these indemnifications are related to tax issues and the majority of these expire in 2021. Those related to environmental issues have terms that are generally indefinite and the maximum amounts of future payments are generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2020, was approximately $50 million. We amortize the indemnification liability over the relevant time period the indemnity is in effect, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. For additional information about environmental liabilities, see Note 12—Contingencies and Commitments.

**Note 12—Contingencies and Commitments**

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various 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 18—Income Taxes, for additional information about income tax-related contingencies.

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

**Environmental**

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

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

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 9—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

**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 and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

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

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, 2020, we had performance obligations secured by letters of credit of $249 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

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

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

In 2016, ConocoPhillips filed a separate and independent arbitration under the rules of the ICC against PDVSA under the contracts that had established the Corocoro Project. On August 2, 2019, the ICC Tribunal awarded ConocoPhillips approximately $33 million plus interest under the Corocoro contracts. ConocoPhillips is seeking recognition and enforcement of the award in various jurisdictions. 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 has appealed these orders and strongly objects to the ONRR claims. The appeals are pending with the Interior Board of Land Appeals (IBLA), except for one order that is the subject of a lawsuit ConocoPhillips filed in 2016 in New Mexico federal court after its appeal was denied by the IBLA.

Beginning in 2017, governmental and other entities in several states in the U.S. have filed lawsuits against 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 any potential financial impact on the company.

In 2016, ConocoPhillips, through its subsidiary, The Louisiana Land and Exploration Company LLC, submitted claims as the largest private wetlands owner in Louisiana within the settlement claims administration process related to the oil spill in the Gulf of Mexico in April 2010. In July 2020, the claims administrator issued an award to the company which, after fees and expenses, totaled approximately $90 million, and was received in the third quarter of 2020.

In October 2020, the Bureau of Safety and Environmental Enforcement (BSEE) ordered the prior owners of Outer Continental Shelf (OCS) Lease P-0166, including ConocoPhillips, to decommission the lease facilities, including two offshore platforms located near Carpinteria, California. This order was sent after the current owner of OCS Lease P-0166 relinquished the lease and abandoned the lease platforms and facilities. Phillips Petroleum Company, a legacy company of ConocoPhillips, held a 25 percent interest in this lease and operated these facilities, but sold its interest approximately 30 years ago. ConocoPhillips has not had any connection to the operation or production on this lease since that time. ConocoPhillips is challenging this order.

**Long-Term Throughput Agreements and Take-or-Pay Agreements**
We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are: 2021—$7 million; 2022—$7 million; 2023—$7 million; 2024—$7 million; 2025—$7 million; and 2026 and after—$51 million. Total payments under the agreements were $25 million in 2020, $25 million in 2019 and $39 million in 2018.

**Note 13—Derivative and Financial Instruments**

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

**Commodity Derivative Instruments**
Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and NGLs.

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

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Assets** | | | |
| Prepaid expenses and other current assets | $ | **229** | 288 |
| Other assets | | **26** | 34 |
| **Liabilities** | | | |
| Other accruals | | **202** | 283 |
| Other liabilities and deferred credits | | **18** | 28 |

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

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| Sales and other operating revenues | $ | **19** | 141 | 45 |
| Other income (loss) | | **4** | 4 | 7 |
| Purchased commodities | | **11** | (118) | (41) |

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

| | Open Position Long/(Short) | |
|---|---|---|
| | **2020** | 2019 |
| **Commodity** | | |
| Natural gas and power (billions of cubic feet equivalent) | | |
| Fixed price | **(20)** | (5) |
| Basis | **(10)** | (23) |

**Foreign Currency Exchange Derivatives**

We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends and 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 recorded as operating activities on our consolidated statement of cash flows. We do not apply hedge accounting to our foreign currency exchange derivatives.

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Assets** | | | |
| Prepaid expenses and other current assets | **$** | **2** | 1 |
| **Liabilities** | | | |
| Other accruals | | **16** | 20 |
| Other liabilities and deferred credits | | - | 8 |

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

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| Foreign currency transaction (gains) losses | **$** | **(40)** | 16 | 1 |

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

| | | In Millions Notional Currency | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Foreign Currency Exchange Derivatives** | | | |
| Buy British pound, sell euro | GBP | - | 4 |
| Sell British pound, buy euro | GBP | **5** | - |
| Sell Canadian dollar, buy U.S. dollar | CAD | **370** | 1,337 |

At December 31, 2020, we had outstanding foreign currency exchange forward contracts to sell $0.45 billion CAD at $0.748 CAD against the U.S. dollar. At December 31, 2019, we had outstanding foreign currency exchange forward contracts to sell $1.35 billion CAD at $0.748 CAD against the U.S. dollar.

**Financial Instruments**

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

- Time deposits: Interest bearing deposits placed with financial institutions for a predetermined 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, 2020 and 2019:

| | Millions of Dollars | | | | | | |
|---|---|---|---|---|---|---|---|
| | Carrying Amount | | | | | | |
| | | Cash and Cash Equivalents | | Short-Term Investments | | Investments and Long-Term Receivables | |
| | | **2020** | 2019 | **2020** | 2019 | **2020** | 2019 |
| **Cash** | $ | **597** | 759 | | | | |
| **Demand Deposits** | | **1,133** | 1,483 | | | | |
| **Time Deposits** | | | | | | | |
| 1 to 90 days | | **1,225** | 2,030 | **2,859** | 1,395 | | |
| 91 to 180 days | | | | **448** | 465 | | |
| Within one year | | | | **13** | - | | |
| One year through five years | | | | | | **1** | - |
| **Commercial Paper** | | | | | | | |
| 1 to 90 days | | - | 413 | - | 1,069 | | |
| **U.S. Government Obligations** | | | | | | | |
| 1 to 90 days | | **23** | 394 | - | - | | |
| | $ | **2,978** | 5,079 | **3,320** | 2,929 | **1** | - |

The following investments in debt securities classified as available for sale are carried on our consolidated balance sheet at fair value as of December 31, 2020 and 2019:

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Carrying Amount | | | | | |
| | Cash and Cash Equivalents | | Short-Term Investments | | Investments and Long-Term Receivables | |
| | **2020** | 2019 | **2020** | 2019 | **2020** | 2019 |
| **Major Security Type** | | | | | | |
| Corporate Bonds | $ **-** | 1 | **130** | 59 | **143** | 99 |
| Commercial Paper | **13** | 8 | **155** | 30 | | |
| U.S. Government Obligations | **-** | - | **4** | 10 | **13** | 15 |
| U.S. Government Agency Obligations | | | | | **17** | - |
| Foreign Government Obligations | | | | | **2** | - |
| Asset-backed Securities | | | **-** | - | **41** | 19 |
| | $ **13** | 9 | **289** | 99 | **216** | 133 |

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

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

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Amortized Cost Basis | | Fair Value | |
| | **2020** | 2019 | **2020** | 2019 |
| **Major Security Type** | | | | |
| Corporate bonds | $ **271** | 159 | **273** | 159 |
| Commercial paper | **168** | 38 | **168** | 38 |
| U.S. government obligations | **17** | 25 | **17** | 25 |
| U.S. government agency obligations | **17** | - | **17** | - |
| Foreign government obligations | **2** | - | **2** | - |
| Asset-backed securities | **41** | 19 | **41** | 19 |
| | $ **516** | 241 | **518** | 241 |

As of December 31, 2020 and December 31, 2019, total unrealized losses for debt securities classified as available for sale with net losses were negligible. Additionally, as of December 31, 2020 and December 31, 2019, investments in these debt securities in an unrealized loss position for which an allowance for credit losses has not been recorded were negligible.

For the year ended December 31, 2020, proceeds from sales and redemptions of investments in debt securities classified as available for sale were $422 million. Gross realized gains and losses included in earnings from those sales and redemptions were negligible. The cost of securities sold and redeemed is determined using the specific identification method.

**Credit Risk**

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

The credit risk from our OTC derivative contracts, such as forwards, swaps and options, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared primarily with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for 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. At our option, we may require collateral to limit the exposure to loss including, letters of credit, prepayments and surety bonds, as well as master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts 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, 2020 and December 31, 2019, was $25 million and $79 million, respectively. For these instruments, no collateral was posted as of December 31, 2020 or December 31, 2019. If our credit rating had been downgraded below investment grade on December 31, 2020, we would have been required to post $23 million of additional collateral, either with cash or letters of credit.

**Note 14—Fair Value Measurement**

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

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

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. There were no material transfers into or out of Level 3 during 2020 or 2019.

**Recurring Fair Value Measurement**

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

- Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 1 also includes our investment in common shares of Cenovus Energy, which is valued using quotes for shares on the NYSE, and our investments in U.S. government obligations classified as available for sale debt securities, which are valued using exchange prices.
- Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase 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, 2020** | | | | December 31, 2019 | | | | |
| | | **Level 1** | **Level 2** | **Level 3** | **Total** | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | | | | | | |
| Investment in Cenovus Energy | **$** | **1,256** | **-** | **-** | **1,256** | 2,111 | - | - | 2,111 |
| Investments in debt securities | | **17** | **501** | **-** | **518** | 25 | 216 | - | 241 |
| Commodity derivatives | | **142** | **101** | **12** | **255** | 172 | 114 | 36 | 322 |
| Total assets | **$** | **1,415** | **602** | **12** | **2,029** | 2,308 | 330 | 36 | 2,674 |
| **Liabilities** | | | | | | | | | |
| Commodity derivatives | **$** | **120** | **91** | **9** | **220** | 174 | 115 | 22 | 311 |
| Total liabilities | **$** | **120** | **91** | **9** | **220** | 174 | 115 | 22 | 311 |

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, 2020** | | | | | | | | |
| Assets | **$** | **255** | **2** | **253** | **157** | **96** | **10** | **86** |
| Liabilities | | **220** | **1** | **219** | **157** | **62** | **4** | **58** |
| December 31, 2019 | | | | | | | | |
| Assets | $ | 322 | 3 | 319 | 193 | 126 | 4 | 122 |
| Liabilities | | 311 | 4 | 307 | 193 | 114 | 12 | 102 |

At December 31, 2020 and December 31, 2019, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

**Non-Recurring Fair Value Measurement**

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

| | | Millions of Dollars | | | |
|---|---|---|---|---|---|
| | | | Fair Value Measurements Using | | |
| | | Fair Value | Level 1 Inputs | Level 2 Inputs | Level 3 Inputs | Before-Tax Loss |
| **Year ended December 31, 2020** | | | | | | |
| Net PP&E (held for use) | | | | | | |
| March 31, 2020 | **$** | **65** | **-** | **-** | **65** | **522** |
| December 31, 2020 | | **268** | **-** | **-** | **268** | **287** |
| Year ended December 31, 2019 | | | | | | |
| Net PP&E (held for sale) | | | | | | |
| November 30, 2019 | $ | 194 | 194 | - | - | 351 |
| December 31, 2019 | | 166 | 166 | - | - | 28 |
| Equity Method Investments | | | | | | |
| March 31, 2019 | | 171 | 171 | - | - | 60 |
| May 31, 2019 | | 30 | - | 30 | - | 95 |

*Net PP&E (held for use)*
During 2020, the estimated fair value of certain non-core 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) |
|---|---|---|---|---|
| **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.*

*Net PP&E (held for sale)*
Net PP&E held for sale was written down to fair value, less costs to sell. The fair value of the assets were determined by their negotiated selling prices (Level 1). For additional information see Note 4—Asset Acquisitions and Dispositions.

*Equity Method Investments*
During 2019, certain equity method investments were determined to have fair values below their carrying amounts, and the impairments were considered to be other than temporary under the guidance of FASB ASC Topic 323. Investments using Level 1 inputs were written down to fair value, less costs to sell, determined by negotiated selling prices. For additional information, see Note 4—Asset Acquisitions and Dispositions and Note 5—Investments, Loans and Long-Term Receivables. An investment using Level 2 inputs was determined to have a fair value below its carrying value, and was written down to fair value.

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

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value. For those investments classified as available for sale debt securities, the carrying amount reported on the balance sheet is fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances—related parties.

- Investment in Cenovus Energy: See Note 6—Investment in Cenovus Energy for a discussion of the carrying value and fair value of our investment in Cenovus Energy common shares.
- Investments in debt securities classified as available for sale: The fair value of investments in debt securities categorized as Level 1 in the fair value hierarchy is measured using exchange prices. The fair value of investments in debt securities categorized as Level 2 in the fair value hierarchy is measured using pricing provided by brokers or pricing service companies that are corroborated with market data. See Note 13—Derivatives and Financial Instruments, for additional information.
- Loans and advances—related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 5—Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of 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. See Note 10—Debt, for additional information.

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

| | Millions of Dollars | | | |
|---|---|---|---|---|
| | Carrying Amount | | Fair Value | |
| | **2020** | 2019 | **2020** | 2019 |
| **Financial assets** | | | | |
| Investment in Cenovus Energy | $ **1,256** | 2,111 | **1,256** | 2,111 |
| Commodity derivatives | **88** | 125 | **88** | 125 |
| Investments in debt securities | **518** | 241 | **518** | 241 |
| Loans and advances—related parties | **220** | 339 | **220** | 339 |
| **Financial liabilities** | | | | |
| Total debt, excluding finance leases | **14,478** | 14,175 | **19,106** | 18,108 |
| Commodity derivatives | **59** | 106 | **59** | 106 |

*Commodity Derivatives*

At December 31, 2020, commodity derivative assets and liabilities are presented net with $10 million in obligations to return cash collateral and $4 million of rights to reclaim cash collateral, respectively. At December 31, 2019, commodity derivative assets and liabilities are presented net with $4 million in obligations to return cash collateral and $12 million of rights to reclaim cash collateral, respectively.

**Note 15—Equity**

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

| | Shares | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Issued** | | | |
| Beginning of year | **1,795,652,203** | 1,791,637,434 | 1,785,419,175 |
| Distributed under benefit plans | **3,192,064** | 4,014,769 | 6,218,259 |
| End of year | **1,798,844,267** | 1,795,652,203 | 1,791,637,434 |
| | | | |
| **Held in Treasury** | | | |
| Beginning of year | **710,783,814** | 653,288,213 | 608,312,034 |
| Repurchase of common stock | **20,018,275** | 57,495,601 | 44,976,179 |
| End of year | **730,802,089** | 710,783,814 | 653,288,213 |

**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, 2020 or 2019.

**Noncontrolling Interests**
In the second quarter of 2020, we completed the divestiture of our subsidiaries that held our Australia-West assets and operations. These assets included the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures in which there was a noncontrolling interest. As a result, as of December 31, 2020, we had no noncontrolling interests. At December 31, 2019, we had $69 million of equity outstanding in the same joint ventures.

**Repurchase of Common Stock**
In late 2016, we initiated our current share repurchase program, which has a current total program authorization of $25 billion of our common stock. Cost of share repurchases were $892 million, $3,500 million, $2,999 million in 2020, 2019 and 2018, respectively. Share repurchases were suspended in the second and third quarters of 2020 in response to the economic downturn. In the fourth quarter of 2020, we resumed share repurchases, repurchasing $0.2 billion of shares in October, until suspending further repurchases upon entry into a definitive agreement to acquire Concho. In February 2021, we resumed share repurchases following our Concho acquisition. Share repurchases since inception of our current program totaled 189 million shares at a cost of $10,517 million, as of December 31, 2020.

**Note 16—Non-Mineral Leases**

The company primarily leases office buildings and drilling equipment, as well as ocean transport vessels, tugboats, corporate aircraft, and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices and other leases include payment provisions 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 11—Guarantees. There are no significant restrictions imposed on us by the lease agreements with regard to dividends, asset dispositions or borrowing ability.

Certain arrangements may contain both lease and non-lease components and we determine if an arrangement 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 | | | |
|---|---|---|---|---|---|
| | | **2020** | | 2019 | |
| | | Operating Leases | Finance Leases | Operating Leases | Finance Leases |
| **Right-of-Use Assets** | | | | | |
| Properties, plants and equipment | | | | | |
| Gross | $ | | **1,375** | | 1,039 |
| Accumulated DD&A | | | **(721)** | | (649) |
| Net PP&E[*] | | | **654** | | 390 |
| Prepaid expenses and other current assets | $ | **-** | | 40 | |
| Other assets | | **783** | | 896 | |
| **Lease Liabilities** | | | | | |
| Short-term debt[**] | $ | | **168** | | 87 |
| Other accruals | | **226** | | 347 | |
| Long-term debt[***] | | | **723** | | 633 |
| Other liabilities and deferred credits | | **559** | | 585 | |
| Total lease liabilities | $ | **785** | **891** | 932 | 720 |

** Includes proportionately consolidated finance lease assets of $258 million at December 31, 2020 and $335 million at December 31, 2019.*
*** Includes proportionately consolidated finance lease liabilities of $97 million at December 31, 2020 and $56 million at December 31, 2019.*
**** Includes proportionately consolidated finance lease liabilities of $522 million at December 31, 2020 and $579 million at December 31, 2019.*

The following table summarizes our lease costs for 2020 and 2019:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Lease Cost[*]** | | | |
| Operating lease cost | $ | **321** | 341 |
| Finance lease cost | | | |
| Amortization of right-of-use assets | | **163** | 99 |
| Interest on lease liabilities | | **34** | 37 |
| Short-term lease cost[**] | | **42** | 77 |
| Total lease cost[***] | $ | **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:

| | **2020** | 2019 |
|---|---|---|
| **Lease Term and Discount Rate** | | |
| Weighted-average term (years) | | |
| Operating leases | **6.11** | 5.19 |
| Finance leases | **7.12** | 8.70 |
| | | |
| Weighted-average discount rate (percent) | | |
| Operating leases | **2.78** | 3.10 |
| Finance leases | **4.27** | 5.53 |

The following table summarizes other lease information for 2020 and 2019:

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Other Information*** | | | |
| Cash paid for amounts included in the measurement of lease liabilities | | | |
| Operating cash flows from operating leases | $ | **232** | 203 |
| Operating cash flows from finance leases | | **11** | 27 |
| Financing cash flows from finance leases | | **255** | 81 |
| Right-of-use assets obtained in exchange for operating lease liabilities | $ | **250** | 499 |
| Right-of-use assets obtained in exchange for finance lease liabilities | | **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, 2020:

| | | Millions of Dollars | |
|---|---|---|---|
| | | Operating Leases | Finance Leases |
| **Maturity of Lease Liabilities** | | | |
| 2021 | $ | 245 | 213 |
| 2022 | | 155 | 162 |
| 2023 | | 116 | 148 |
| 2024 | | 94 | 113 |
| 2025 | | 55 | 87 |
| Remaining years | | 200 | 320 |
| Total* | | 865 | 1,043 |
| Less: portion representing imputed interest | | (80) | (152) |
| Total lease liabilities | $ | 785 | 891 |

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

For the year ended December 31, 2018 operating lease rental expense pursuant to ASC Topic 840 was:

| | | Millions of Dollars |
|---|---|---|
| Total rentals | $ | 253 |
| Less: sublease rentals | | (16) |
| | $ | 237 |

### Note 17—Employee Benefit Plans

### Pension and Postretirement Plans

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

| | | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|---|
| | | Pension Benefits | | | | Other Benefits | |
| | | **2020** | | 2019 | | **2020** | 2019 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Change in Benefit Obligation** | | | | | | | |
| Benefit obligation at January 1 | **$** | **2,319** | **3,880** | 2,136 | 3,438 | **216** | 218 |
| Service cost | | **85** | **54** | 79 | 69 | **2** | 1 |
| Interest cost | | **66** | **85** | 79 | 97 | **6** | 8 |
| Plan participant contributions | | **-** | **1** | - | 2 | **18** | 20 |
| Plan amendments | | **-** | **2** | - | - | **(30)** | - |
| Actuarial loss | | **319** | **398** | 278 | 387 | **7** | 27 |
| Benefits paid | | **(241)** | **(151)** | (253) | (147) | **(49)** | (59) |
| Curtailment | | **-** | **2** | - | (69) | **-** | - |
| Recognition of termination benefits | | **-** | **3** | - | 1 | **-** | - |
| Foreign currency exchange rate change | | **-** | **129** | - | 102 | **-** | 1 |
| Benefit obligation at December 31* | **$** | **2,548** | **4,403** | 2,319 | 3,880 | **170** | 216 |
| **Accumulated benefit obligation portion of above at December 31:* | *$* | ***2,359*** | ***4,095*** | *2,161* | *3,594* | | |
| **Change in Fair Value of Plan Assets** | | | | | | | |
| Fair value of plan assets at January 1 | **$** | **1,591** | **4,306** | 1,336 | 3,358 | **-** | - |
| Actual return on plan assets | | **321** | **416** | 273 | 529 | **-** | - |
| Company contributions | | **99** | **60** | 235 | 464 | **31** | 39 |
| Plan participant contributions | | **-** | **1** | - | 2 | **18** | 20 |
| Benefits paid | | **(241)** | **(151)** | (253) | (147) | **(49)** | (59) |
| Foreign currency exchange rate change | | **-** | **161** | - | 100 | **-** | - |
| Fair value of plan assets at December 31 | **$** | **1,770** | **4,793** | 1,591 | 4,306 | **-** | - |
| **Funded Status** | **$** | **(778)** | **390** | (728) | 426 | **(170)** | (216) |

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | | Other Benefits | |
| | **2020** | | 2019 | | **2020** | 2019 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Amounts Recognized in the Consolidated Balance Sheet at December 31** | | | | | | |
| Noncurrent assets | $ - | **746** | - | 765 | - | - |
| Current liabilities | **(56)** | **(11)** | (21) | (6) | **(39)** | (42) |
| Noncurrent liabilities | **(722)** | **(345)** | (707) | (333) | **(131)** | (174) |
| Total recognized | $ **(778)** | **390** | (728) | 426 | **(170)** | (216) |
| **Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31** | | | | | | |
| Discount rate | **2.30** % | **1.80** | 3.25 | 2.35 | **2.15** | 3.10 |
| Rate of compensation increase | **4.00** | **3.10** | 4.00 | 3.35 | | |
| Interest crediting rate for applicable benefits | **2.10** | - | 4.10 | - | | |
| **Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31** | | | | | | |
| Discount rate | **3.05** % | **2.35** | 3.95 | 2.90 | **3.10** | 4.05 |
| Expected return on plan assets | **5.80** | **3.60** | 5.80 | 4.10 | | |
| Rate of compensation increase | **4.00** | **3.35** | 4.00 | 3.65 | | |
| Interest crediting rate for applicable benefits | **4.10** | - | 4.35 | - | | |

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

The following tables set forth information related to the Company's pension plans with projected and accumulated benefit obligations in excess of the fair value of the plans' assets as of December 31, 2020 and 2019:

| | Millions of Dollars | | | | |
|---|---|---|---|---|---|
| | Pension Benefits | | | | |
| | | **2020** | | 2019 | |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. |
| **Pension Plans with Projected Benefit Obligation in Excess of Plan Assets** | | | | | |
| Projected benefit obligation | $ | **2,548** | **391** | 2,319 | 355 |
| Fair value of plan assets | | **1,770** | **35** | 1,591 | 44 |
| **Pension Plans with Accumulated Benefit Obligation in Excess of Plan Assets** | | | | | |
| Accumulated benefit obligation | $ | **2,359** | **338** | 2,161 | 299 |
| Fair value of plan assets | | **1,770** | **35** | 1,591 | 44 |

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

| | Millions of Dollars | | | | | | |
|---|---|---|---|---|---|---|---|
| | Pension Benefits | | | | | Other Benefits | |
| | | **2020** | | 2019 | | **2020** | 2019 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| Unrecognized net actuarial loss | $ | **467** | **326** | 479 | 227 | **14** | 8 |
| Unrecognized prior service credit | | **-** | **-** | - | (2) | **(182)** | (183) |

| | Millions of Dollars | | | | | | |
|---|---|---|---|---|---|---|---|
| | Pension Benefits | | | | | Other Benefits | |
| | | **2020** | | 2019 | | **2020** | 2019 |
| | | **U.S.** | **Int'l.** | U.S. | Int'l. | | |
| **Sources of Change in Other Comprehensive Income (Loss)** | | | | | | | |
| Net gain (loss) arising during the period | $ | **(83)** | **(120)** | (79) | 51 | **(7)** | (27) |
| Amortization of actuarial (gain) loss included in income (loss)* | | **95** | **21** | 116 | 32 | **1** | (2) |
| Net change during the period | $ | **12** | **(99)** | 37 | 83 | **(6)** | (29) |
| | | | | | | | |
| Prior service credit (cost) arising during the period | $ | **-** | **(1)** | - | - | **30** | - |
| Amortization of prior service cost (credit) included in income (loss) | | **-** | **(1)** | - | (2) | **(31)** | (33) |
| Net change during the period | $ | **-** | **(2)** | - | (2) | **(1)** | (33) |

**Includes settlement (gains) losses recognized in 2020 and 2019.*

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

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Pension Benefits | | | | | | Other Benefits | | |
| | **2020** | | 2019 | | 2018 | | **2020** | 2019 | 2018 |
| | **U.S.** | **Int'l.** | U.S. | Int'l. | U.S. | Int'l. | | | |
| **Components of Net Periodic Benefit Cost** | | | | | | | | | |
| Service cost | $ **85** | **54** | 79 | 69 | 83 | 81 | **2** | 1 | 1 |
| Interest cost | **66** | **85** | 79 | 97 | 99 | 107 | **6** | 8 | 8 |
| Expected return on plan assets | **(85)** | **(145)** | (74) | (138) | (114) | (155) | - | - | - |
| Amortization of prior service credit | - | **(1)** | - | (2) | - | (5) | **(31)** | (33) | (35) |
| Recognized net actuarial loss (gain) | **51** | **22** | 54 | 32 | 53 | 31 | **1** | (2) | (1) |
| Settlements loss (gain) | **44** | **(1)** | 62 | - | 196 | - | - | - | - |
| Net periodic benefit cost | $ **161** | **14** | 200 | 58 | 317 | 59 | **(22)** | (26) | (27) |

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 $43 million in 2020, $62 million in 2019, and $196 million in 2018 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

During 2020 and 2019, the actuarial losses related to the benefit obligation for U.S. and international plans were primarily related to a decrease in the discount rates.

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

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

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 7 percent in 2021 that declines to 5 percent by 2028. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes an ultimate health care cost trend rate of 4 percent achieved in 2021 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 28 percent equity securities, 68 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, 2020 and 2019.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- Fair values of corporate debt securities, agency and mortgage-backed securities and government 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, 2020, the participating interest in the annuity contract was valued at $94 million and consisted of $233 million in debt securities, less $139 million for the accumulated benefit obligation covered by the contract. At December 31, 2019, the participating interest in the annuity contract was valued at $95 million and consisted of $235 million in debt securities, less $140 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 |
| **2020** | | | | | | | | | |
| Equity securities | | | | | | | | | |
| U.S. | $ | - | 3 | 5 | 8 | - | - | - | - |
| International | | 99 | - | - | 99 | - | - | - | - |
| Mutual funds | | 72 | - | - | 72 | 235 | 734 | - | 969 |
| 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 | 734 | 142 | 1,646 |
| | | | | | | | | | |
| Investments measured at net asset value* | | | | | | | | | |
| Equity securities | | | | | | | | | |
| Common/collective trusts | $ | | | | 678 | | | | 2,962 |
| Debt securities | | | | | | | | | |
| Common/collective trusts | | | | | 730 | | | | 67 |
| Cash and cash equivalents | | | | | 8 | | | | - |
| Real estate | | | | | 79 | | | | 112 |
| Total** | $ | 171 | 4 | 5 | 1,675 | 770 | 734 | 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.*

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

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

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

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

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 2021, we expect to contribute approximately $265 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $75 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. | |
| 2021 | $ | 532 | 147 | 25 |
| 2022 | | 289 | 151 | 21 |
| 2023 | | 248 | 156 | 18 |
| 2024 | | 232 | 162 | 16 |
| 2025 | | 215 | 166 | 14 |
| 2026–2030 | | 845 | 897 | 53 |

**Severance Accrual**
The following table summarizes our severance accrual activity for 2020, 2019 and 2018:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| Balance at January 1 | $ | **23** | 48 | 53 |
| Accruals | | **14** | (1) | 70 |
| Benefit payments | | **(13)** | (24) | (73) |
| Foreign currency translation adjustments | | **-** | - | (2) |
| Balance at December 31 | **$** | **24** | 23 | 48 |

Of the remaining balance at December 31, 2020, $8 million is classified as short-term.

**Defined Contribution Plans**
Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 17 investment options. Employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Effective January 1, 2019, new employees, rehires, and employees that elected to opt out of Title II 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 $62 million in 2020, $82 million in 2019, and $82 million in 2018.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $25 million in 2020, $30 million in 2019, and $31 million in 2018.

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

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

We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

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

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Compensation cost | $ **159** | 274 | 265 |
| Tax benefit | **40** | 71 | 64 |

**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 for 2020 awards.

The following summarizes our stock option activity for the year ended December 31, 2020:

| | Options | Weighted-Average Exercise Price | Millions of Dollars Aggregate Intrinsic Value |
|---|---|---|---|
| Outstanding at December 31, 2019 | 18,040,197 | $ 54.11 | $ 206 |
| Exercised | **(1,111,805)** | **38.80** | **23** |
| Forfeited | **(5,867)** | **49.76** | |
| Expired or cancelled | - | | |
| **Outstanding at December 31, 2020** | **16,922,525** | **$ 55.12** | **$ 22** |
| **Vested at December 31, 2020** | **16,922,525** | **$ 55.12** | **$ 22** |
| **Exercisable at December 31, 2020** | **16,922,525** | **$ 55.12** | **$ 22** |

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2020, were all 3.66 years. The aggregate intrinsic value of options exercised was $39 million in 2019 and $94 million in 2018.

During 2020, we received $43 million in cash and realized a tax benefit of $9 million from the exercise of options. At December 31, 2020, all outstanding stock options were fully vested and there was no remaining compensation cost to be recorded.

**Stock Unit Program—**Generally, restricted stock units are granted annually under the provisions of the 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 that is charged to retained earnings. Executive recipients receive an accrued reinvested dividend equivalent, subject to the terms and conditions of the award, that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock-settled stock unit activity for the year ended December 31, 2020:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2019 | 6,223,046 | $ 55.99 | |
| Granted | **2,890,840** | **57.40** | |
| Forfeited | **(127,181)** | **55.84** | |
| Issued | **(2,554,720)** | **50.16** | **$ 143** |
| **Outstanding at December 31, 2020** | **6,431,985** | **$ 58.94** | |
| **Not Vested at December 31, 2020** | **4,230,413** | **59.01** | |

At December 31, 2020, the remaining unrecognized compensation cost from the unvested stock-settled units was $101 million, which will be recognized over a weighted-average period of 1.71 years, the longest period being 2.14 years. The weighted-average grant date fair value of stock unit awards granted during 2019 and 2018 was $67.77 and $52.45, respectively. The total fair value of stock units issued during 2019 and 2018 was $225 million and $154 million, respectively.

*Cash-Settled*
Cash settled executive restricted stock units granted in 2018 and 2019 replaced the stock option program. These restricted stock units, subject to elections to defer, will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not settled until the earlier of separation from the company or the end of the 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, 2020:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2019 | 596,991 | $ 64.54 | |
| Granted | **24,437** | **41.59** | |
| Forfeited | **(5,622)** | **40.01** | |
| Issued | **(1,191)** | **40.20** | **$ -** |
| **Outstanding at December 31, 2020** | **614,615** | **$ 39.95** | |
| **Not Vested at December 31, 2020** | **121,696** | **39.95** | |

At December 31, 2020, the remaining unrecognized compensation cost from the unvested cash-settled units was $1 million, which will be recognized over a weighted-average period of 1 year, the longest period being 1.12 years. The weighted-average grant date fair value of stock unit awards granted during 2019 and 2018 were $68.20 and $53.68, respectively. The total fair value of stock units issued during 2019 and 2018 were $6 million and $1 million, respectively.

**Performance Share Program**—Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

*Stock-Settled*

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee's separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2020:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2019 | 2,024,824 | $ 50.55 | |
| Granted | **26,244** | **58.61** | |
| Forfeited | - | | |
| Issued | **(314,340)** | **51.15** | **$ 13** |
| **Outstanding at December 31, 2020** | **1,736,728** | **$ 50.56** | |
| **Not Vested at December 31, 2020** | **3,191** | **$ 48.61** | |

At December 31, 2020, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was zero. The weighted-average grant date fair value of stock-settled PSUs granted during 2019 and 2018 was $68.90 and $53.28, respectively. The total fair value of stock-settled PSUs issued during 2019 and 2018 was $25 million and $29 million, respectively.

*Cash-Settled*

In connection with and immediately following the separation of our Downstream businesses in 2012, grants 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, 2020:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2019 | 609,274 | $ 64.54 | |
| Granted | **1,491,098** | **58.61** | |
| Forfeited | - | | |
| Settled | **(1,975,843)** | **58.54** | **$ 116** |
| **Outstanding at December 31, 2020** | **124,529** | **$ 39.95** | |

At December 31, 2020, all outstanding cash-settled performance awards were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of cash-settled PSUs granted during 2019 and 2018 was $68.90 and $53.28, respectively. The total fair value of cash-settled performance share awards settled during 2019 and 2018 was $171 million and $22 million, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards terminated at the end of the three-year performance period and were replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards terminated at the end of the three-year performance period and were settled after the performance period ended. There is no effect on recognition of compensation expense.

**Other**—In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued as part of our non-employee director compensation program for current and former members of the company's Board of Directors or as part of an executive compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2020:

| | Stock Units | Weighted-Average Grant Date Fair Value | Millions of Dollars Total Fair Value |
|---|---|---|---|
| Outstanding at December 31, 2019 | 991,908 | $ 47.24 | |
| Granted | **77,824** | **51.46** | |
| Cancelled | **(1,336)** | **23.09** | |
| Issued | **(98,297)** | **45.57** | **$ 6** |
| **Outstanding at December 31, 2020** | **970,099** | **$ 47.78** | |

At December 31, 2020, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2019 and 2018 was $63.58 and $62.01, respectively. The total fair value of awards issued during 2019 and 2018 was $11 million and $17 million, respectively.

**Note 18—Income Taxes**

Components of income tax expense (benefit) were:

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| **Income Taxes** | | | | |
| Federal | | | | |
| Current | $ | **3** | 18 | 4 |
| Deferred | | **(625)** | (113) | 545 |
| Foreign | | | | |
| Current | | **350** | 2,545 | 3,273 |
| Deferred | | **(70)** | (323) | (166) |
| State and local | | | | |
| Current | | **(4)** | 148 | 108 |
| Deferred | | **(139)** | (8) | (96) |
| | $ | **(485)** | 2,267 | 3,668 |

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Deferred Tax Liabilities** | | | |
| PP&E and intangibles | $ | **7,744** | 8,660 |
| Inventory | | **64** | 35 |
| Other | | **242** | 234 |
| Total deferred tax liabilities | | **8,050** | 8,929 |
| | | | |
| **Deferred Tax Assets** | | | |
| Benefit plan accruals | | **540** | 542 |
| Asset retirement obligations and accrued environmental costs | | **2,262** | 2,339 |
| Investments in joint ventures | | **1,653** | 1,722 |
| Other financial accruals and deferrals | | **907** | 777 |
| Loss and credit carryforwards | | **8,904** | 8,968 |
| Other | | **365** | 345 |
| Total deferred tax assets | | **14,631** | 14,693 |
| Less: valuation allowance | | **(9,965)** | (10,214) |
| Total deferred tax assets net of valuation allowance | | **4,666** | 4,479 |
| Net deferred tax liabilities | $ | **3,384** | 4,450 |

At December 31, 2020, noncurrent assets and liabilities included deferred taxes of $363 million and $3,747 million, respectively. At December 31, 2019, noncurrent assets and liabilities included deferred taxes of $184 million and $4,634 million, respectively.

At December 31, 2020, the loss and credit carryforward deferred tax assets were primarily related to U.S. foreign tax credit carryforwards of $7 billion and various jurisdictions net operating loss and credit carryforwards of $1.9 billion. If not utilized, U.S. foreign tax credits and net operating losses will begin to expire in 2021.

The following table shows a reconciliation of the beginning and ending deferred tax asset valuation allowance for 2020, 2019 and 2018:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Balance at January 1 | $ **10,214** | 3,040 | 1,254 |
| Charged to expense (benefit) | **460** | (225) | (26) |
| Other* | **(709)** | 7,399 | 1,812 |
| Balance at December 31 | $ **9,965** | 10,214 | 3,040 |

**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. Certain items in the prior year have been reclassed to conform with the current year presentation, with no impacts to beginning and ending balances.*

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. At December 31, 2020, we have maintained a valuation allowance with respect to substantially all U.S. foreign tax credit carryforwards as well as certain net operating loss carryforwards for various jurisdictions. During 2020, the valuation allowance movement charged to earnings primarily relates to capital losses in Australia and to the fair value measurement of our Cenovus Energy common shares that are not expected to be realized. Other movements are primarily related to valuation allowances on expiring tax attributes. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects deferred tax assets, net of valuation allowances, will primarily be realized as offsets to reversing deferred tax liabilities.

On December 2, 2019, the Internal Revenue Service finalized foreign tax credit regulations related to the 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, 2020, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,982 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 $199 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2020, 2019 and 2018:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Balance at January 1 | $ **1,177** | 1,081 | 882 |
| Additions based on tax positions related to the current year | **6** | 9 | 268 |
| Additions for tax positions of prior years | **67** | 120 | 43 |
| Reductions for tax positions of prior years | **(34)** | (22) | (73) |
| Settlements | **(9)** | (9) | (35) |
| Lapse of statute | **(1)** | (2) | (4) |
| Balance at December 31 | $ **1,206** | 1,177 | 1,081 |

Included in the balance of unrecognized tax benefits for 2020, 2019 and 2018 were $1,128 million, $1,100 million and $1,081 million, respectively, which, if recognized, would impact our effective tax rate. The balance of the unrecognized tax benefits increased in 2019 mainly due to the treatment of our PDVSA settlement. The balance of the unrecognized tax benefits increased in 2018 mainly due to the treatment of distributions from certain foreign subsidiaries. See Note 12—Contingencies and Commitments, for more information on the PDVSA settlement.

At December 31, 2020, 2019 and 2018, accrued liabilities for interest and penalties totaled $46 million, $42 million and $45 million, respectively, net of accrued income taxes. Interest and penalties resulted in a reduction to earnings of $4 million in 2020, a benefit to earnings of $3 million in 2019, and a benefit to earnings of $4 million in 2018, respectively.

We file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: U.K. (2015), Canada (2014), U.S. (2014) and Norway (2019). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. Consequently, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

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

| | | Millions of Dollars | | | Percent of Pre-Tax Income (Loss) | | |
|---|---|---|---|---|---|---|---|
| | | **2020** | 2019 | 2018 | **2020** | 2019 | 2018 |
| Income (loss) before income taxes | | | | | | | |
| United States | $ | **(3,587)** | 4,704 | 2,867 | **114.2 %** | 49.4 | 28.7 |
| Foreign | | **447** | 4,820 | 7,106 | **(14.2)** | 50.6 | 71.3 |
| | $ | **(3,140)** | 9,524 | 9,973 | **100.0 %** | 100.0 | 100.0 |
| | | | | | | | |
| Federal statutory income tax | $ | **(659)** | 2,000 | 2,095 | **21.0 %** | 21.0 | 21.0 |
| Non-U.S. effective tax rates | | **194** | 1,399 | 1,766 | **(6.2)** | 14.7 | 17.7 |
| Tax Legislation | | - | - | (10) | - | - | (0.1) |
| Australia disposition | | **(349)** | - | - | **11.1** | - | - |
| U.K. disposition | | - | (732) | (150) | - | (7.7) | (1.5) |
| Recovery of outside basis | | **(22)** | (77) | (21) | **0.7** | (0.8) | (0.2) |
| Adjustment to tax reserves | | **18** | 9 | (4) | **(0.6)** | 0.1 | - |
| Adjustment to valuation allowance | | **460** | (225) | (26) | **(14.6)** | (2.4) | (0.3) |
| State income tax | | **(112)** | 123 | 135 | **3.6** | 1.3 | 1.4 |
| Malaysia Deepwater Incentive | | - | (164) | - | - | (1.7) | - |
| Enhanced oil recovery credit | | **(6)** | (27) | (99) | **0.2** | (0.3) | (1.0) |
| Other | | **(9)** | (39) | (18) | **0.3** | (0.4) | (0.2) |
| | $ | **(485)** | 2,267 | 3,668 | **15.5 %** | 23.8 | 36.8 |

Our effective tax rate for 2020 was impacted by the disposition of our Australia-West assets as well as the valuation allowance related to the fair value measurement of our Cenovus Energy common shares. The Australia-West disposition generated a before-tax gain of $587 million with an associated tax benefit of $10 million and resulted in the de-recognition of deferred tax assets resulting in $92 million of tax expense. The disposition also generated an Australia capital loss tax benefit of $313 million which has been fully offset by a valuation allowance. Due to changes in the fair market value of Cenovus Energy common shares, the valuation allowance was increased by $178 million to offset the expected capital loss.

Our effective tax rate for 2019 was favorably impacted by the sale of two of our U.K. subsidiaries. The disposition generated a before-tax gain of more than $1.7 billion with an associated tax benefit of $335 million. The disposition generated a U.S. capital loss of approximately $2.1 billion which has generated a U.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 4—Asset Acquisitions and Dispositions, for additional information on the disposition.

During the third quarter of 2019, we received final partner approval in Malaysia Block G to claim certain deepwater tax credits. As a result, we recorded an income tax benefit of $164 million.

The decrease in the effective tax rate for 2018 was primarily due to the impact of the Clair Field disposition in the U.K. and our overall income position, partially offset by our change in mix of income among taxing jurisdictions. Our effective tax rate for 2018 was favorably impacted by the sale of a U.K. subsidiary to BP. The subsidiary held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the U.K. The disposition generated a before-tax gain of $715 million with no associated tax cost. See Note 4—Asset Acquisitions and Dispositions, for additional information on the disposition.

As a result of the COVID-19 pandemic and the resulting economic uncertainty, many countries in which we operate, including Australia, Canada, Norway and the U.S., have enacted responsive tax legislation. During the second quarter, Norway enacted legislation to accelerate the recovery of capital expenditures and allow immediate monetization of tax losses. As a result, in the second quarter of 2020, we recorded an increase to our net deferred tax liability of $120 million and a decrease to our accrued income and other taxes liability of $124 million. Legislation in other jurisdictions did not have a material impact to ConocoPhillips.

**Note 19—Accumulated Other Comprehensive Loss**

Accumulated other comprehensive loss in the equity section of the balance sheet included:

| | | Millions of Dollars | | | |
|---|---|---|---|---|---|
| | | Defined Benefit Plans | Net Unrealized Loss on Securities | Foreign Currency Translation | Accumulated Other Comprehensive Loss |
| December 31, 2017 | $ | (400) | (58) | (5,060) | (5,518) |
| Other comprehensive income (loss) | | 39 | - | (642) | (603) |
| Cumulative effect of adopting ASU No. 2016-01* | | - | 58 | - | 58 |
| December 31, 2018 | | (361) | - | (5,702) | (6,063) |
| Other comprehensive income | | 51 | - | 695 | 746 |
| Cumulative effect of adopting ASU No. 2018-02** | | (40) | - | - | (40) |
| December 31, 2019 | | (350) | - | (5,007) | (5,357) |
| Other comprehensive income (loss) | | **(75)** | **2** | **212** | **139** |
| **December 31, 2020** | **$** | **(425)** | **2** | **(4,795)** | **(5,218)** |

**We adopted ASU No. 2016-01, "Recognition and Measurement of Financial Assets and Liabilities," beginning January 1, 2018.*
***We adopted ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income," beginning 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. For additional information related to this disposition, see Note 4—Asset Acquisitions and Dispositions.

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

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| Defined Benefit Plans | $ | **72** | 88 |
| *Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:* | *$* | ***13*** | *23* |

*See Note 17—Employee Benefit Plans, for additional information.*

## Note 20—Cash Flow Information

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| **Noncash Investing Activities** | | | | |
| Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations | $ | **(116)** | 205 | 395 |
| Increase (decrease) in assets and liabilities acquired in a nonmonetary exchange* | | | | |
| Accounts receivable | | - | - | (44) |
| Inventories | | - | - | 42 |
| Investments and long-term receivables | | - | - | 15 |
| PP&E | | - | - | 1,907 |
| Other long-term assets | | - | - | (9) |
| Accounts payable | | - | - | 7 |
| Accrued income and other taxes | | - | - | 40 |
| **Cash Payments** | | | | |
| Interest | $ | **785** | 810 | 772 |
| Income taxes | | **905** | 2,905 | 2,976 |
| **Net Sales (Purchases) of Investments** | | | | |
| Short-term investments purchased | $ | **(12,435)** | (4,902) | (1,953) |
| Short-term investments sold | | **12,015** | 2,138 | 3,573 |
| Investments and long-term receivables purchased | | **(325)** | (146) | - |
| Investments and long-term receivables sold | | **87** | - | - |
| | $ | **(658)** | (2,910) | 1,620 |

**See Note 4—Asset Acquisitions and Dispositions.*

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

We collected $330 million and $430 million in 2019 and 2018, respectively, from PDVSA under a settlement agreement related to an award issued by the ICC Tribunal in 2018. For more information on these settlements, see Note 12—Contingencies and Commitments. We collected $262 million from Ecuador in 2018, as installment payments related to an agreement reached with Ecuador in 2017.

In 2019, we made a $324 million contribution to our U.K. pension plan. We made discretionary payments to our domestic qualified pension plan of $120 million in 2018.

**Note 21—Other Financial Information**

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| **Interest and Debt Expense** | | | | |
| Incurred | | | | |
| Debt | $ | **788** | 799 | 838 |
| Other | | **73** | 36 | 67 |
| | | **861** | 835 | 905 |
| Capitalized | | **(55)** | (57) | (170) |
| Expensed | $ | **806** | 778 | 735 |
| | | | | |
| **Other Income (Loss)** | | | | |
| Interest income | $ | **100** | 166 | 97 |
| Unrealized gains (losses) on Cenovus Energy common shares* | | **(855)** | 649 | (437) |
| Other, net | | **246** | 543 | 513 |
| | $ | **(509)** | 1,358 | 173 |

**See Note 6—Investment in Cenovus Energy, for additional information.*

| | | | | |
|---|---|---|---|---|
| **Research and Development Expenditures**—expensed | $ | **75** | 82 | 78 |
| **Shipping and Handling Costs** | $ | **857** | 1,008 | 1,075 |
| **Foreign Currency Transaction (Gains) Losses**—after-tax | | | | |
| Alaska | $ | **-** | - | - |
| Lower 48 | | **-** | - | - |
| Canada | | **(7)** | 5 | (11) |
| Europe, Middle East and North Africa | | **(15)** | - | (26) |
| Asia Pacific | | **(11)** | 31 | 3 |
| Other International | | **2** | 1 | - |
| Corporate and Other | | **(31)** | 21 | 21 |
| | $ | **(62)** | 58 | (13) |

| | | Millions of Dollars | |
|---|---|---|---|
| | | **2020** | 2019 |
| **Properties, Plants and Equipment** | | | |
| Proved properties | $ | **94,312** | 88,284 * |
| Unproved properties | | **4,141** | 3,980 * |
| Other | | **3,653** | 5,482 |
| Gross properties, plants and equipment | | **102,106** | 97,746 |
| Less: Accumulated depreciation, depletion and amortization | | **(62,213)** | (55,477)* |
| Net properties, plants and equipment | $ | **39,893** | 42,269 |

**Excludes assets classified as held for sale at December 31, 2019. See Note 4—Asset Acquisitions and Dispositions, for additional information.*

**Note 22—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 17—Employee Benefit Plans.

Significant transactions with our equity affiliates were:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Operating revenues and other income | $ **79** | 89 | 98 |
| Purchases | - | 38 | 98 |
| Operating expenses and selling, general and administrative expenses | **63** | 65 | 60 |
| Net interest income* | **(5)** | (13) | (14) |

**We paid interest to, or received interest from, various affiliates. See Note 5—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

**Note 23—Sales and Other Operating Revenues**

**Revenue from Contracts with Customers**
The following table provides further disaggregation of our consolidated sales and other operating revenues:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| Revenue from contracts with customers | $ **13,662** | 26,106 | 28,098 |
| Revenue from contracts outside the scope of ASC Topic 606 | | | |
| Physical contracts meeting the definition of a derivative | **5,177** | 6,558 | 8,218 |
| Financial derivative contracts | **(55)** | (97) | 101 |
| Consolidated sales and other operating revenues | $ **18,784** | 32,567 | 36,417 |

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 24—Segment Disclosures and Related Information:

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Revenue from Outside the Scope of ASC Topic 606 by Segment** | | | |
| Lower 48 | $ **3,966** | 4,989 | 6,358 |
| Canada | **727** | 691 | 629 |
| Europe, Middle East and North Africa | **484** | 878 | 1,231 |
| Physical contracts meeting the definition of a derivative | $ **5,177** | 6,558 | 8,218 |

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Revenue from Outside the Scope of ASC Topic 606 by Product** | | | |
| Crude oil | **$ 395** | 804 | 1,112 |
| Natural gas | **4,339** | 5,313 | 6,734 |
| Other | **443** | 441 | 372 |
| Physical contracts meeting the definition of a derivative | **$ 5,177** | 6,558 | 8,218 |

**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, 2020, the "Accounts and notes receivable" line on our consolidated balance sheet included trade receivables of $1,827 million compared with $2,372 million at December 31, 2019, and included both contracts with customers within the scope of ASC Topic 606 and those that are outside the scope of ASC Topic 606. We typically receive payment within 30 days or less (depending on the terms of the invoice) once delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical gas 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, 2019 | $ **80** |
| Contractual payments received | **17** |
| **At December 31, 2020** | $ **97** |
| | |
| **Amounts Recognized in the Consolidated Balance Sheet at December 31, 2020** | |
| Current liabilities | $ **56** |
| Noncurrent liabilities | **41** |
| | $ **97** |

We expect to recognize the contract liabilities as of December 31, 2020, as revenue during 2021 and 2022. There was no revenue recognized during the year ended December 31, 2020.

**Note 24—Segment Disclosures and Related Information**

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a 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—Accounting Policies. Intersegment sales are at prices that approximate market.

Effective with the third quarter of 2020, we restructured our segments to align with changes to our internal organization. The Middle East business was realigned from the Asia Pacific and Middle East segment to the Europe and North Africa segment. The segments have been renamed the Asia Pacific segment and the Europe, Middle East and North Africa segment. We have revised segment information disclosures and segment performance metrics presented within our results of operations for the current and prior comparative periods.

**Analysis of Results by Operating Segment**

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Sales and Other Operating Revenues** | | | |
| Alaska | $ **3,408** | 5,483 | 5,740 |
| Intersegment eliminations | **(11)** | - | - |
| Alaska | **3,397** | 5,483 | 5,740 |
| Lower 48 | **9,872** | 15,514 | 17,029 |
| Intersegment eliminations | **(51)** | (46) | (40) |
| Lower 48 | **9,821** | 15,468 | 16,989 |
| Canada | **1,666** | 2,910 | 3,184 |
| Intersegment eliminations | **(405)** | (1,141) | (1,160) |
| Canada | **1,261** | 1,769 | 2,024 |
| Europe, Middle East and North Africa | **1,919** | 5,101 | 6,635 |
| Intersegment eliminations | **(2)** | - | - |
| Europe, Middle East and North Africa | **1,917** | 5,101 | 6,635 |
| Asia Pacific | **2,363** | 4,525 | 4,861 |
| Other International | **7** | - | - |
| Corporate and Other | **18** | 221 | 168 |
| Consolidated sales and other operating revenues | $ **18,784** | 32,567 | 36,417 |

The market for our products is large and diverse, therefore, our sales and other operating revenues are not dependent upon any single customer.

| | | Millions of Dollars | | |
|---|---|---|---|---|
| | | **2020** | 2019 | 2018 |
| **Depreciation, Depletion, Amortization and Impairments** | | | | |
| Alaska | $ | **996** | 805 | 760 |
| Lower 48 | | **3,358** | 3,224 | 2,370 |
| Canada | | **342** | 232 | 324 |
| Europe, Middle East and North Africa | | **775** | 887 | 1,041 |
| Asia Pacific | | **809** | 1,285 | 1,382 |
| Other International | | **-** | - | - |
| Corporate and Other | | **54** | 62 | 106 |
| Consolidated depreciation, depletion, amortization and impairments | $ | **6,334** | 6,495 | 5,983 |
| | | | | |
| **Equity in Earnings of Affiliates** | | | | |
| Alaska | $ | **(7)** | 7 | 6 |
| Lower 48 | | **(11)** | (159) | 1 |
| Canada | | **-** | - | - |
| Europe, Middle East and North Africa | | **311** | 470 | 744 |
| Asia Pacific | | **137** | 461 | 323 |
| Other International | | **2** | - | - |
| Corporate and Other | | **-** | - | - |
| Consolidated equity in earnings of affiliates | $ | **432** | 779 | 1,074 |
| | | | | |
| **Income Tax Provision (Benefit)** | | | | |
| Alaska | $ | **(256)** | 472 | 376 |
| Lower 48 | | **(378)** | 137 | 474 |
| Canada | | **(185)** | (43) | (96) |
| Europe, Middle East and North Africa | | **136** | 1,425 | 2,259 |
| Asia Pacific | | **294** | 501 | 728 |
| Other International | | **(20)** | 8 | 30 |
| Corporate and Other | | **(76)** | (233) | (103) |
| Consolidated income tax provision (benefit) | $ | **(485)** | 2,267 | 3,668 |
| | | | | |
| **Net Income (Loss) Attributable to ConocoPhillips** | | | | |
| Alaska | $ | **(719)** | 1,520 | 1,814 |
| Lower 48 | | **(1,122)** | 436 | 1,747 |
| Canada | | **(326)** | 279 | 63 |
| Europe, Middle East and North Africa | | **448** | 3,170 | 2,594 |
| Asia Pacific | | **962** | 1,483 | 1,342 |
| Other International | | **(64)** | 263 | 364 |
| Corporate and Other | | **(1,880)** | 38 | (1,667) |
| Consolidated net income (loss) attributable to ConocoPhillips | $ | **(2,701)** | 7,189 | 6,257 |

| | Millions of Dollars | | |
|---|---|---|---|
| | **2020** | 2019 | 2018 |
| **Investments in and Advances to Affiliates** | | | |
| Alaska | $ **62** | 83 | 86 |
| Lower 48 | **25** | 35 | 378 |
| Canada | **-** | - | - |
| Europe, Middle East and North Africa | **918** | 1,070 | 1,311 |
| Asia Pacific | **6,705** | 7,265 | 7,565 |
| Other International | **-** | - | - |
| Corporate and Other | **-** | - | - |
| Consolidated investments in and advances to affiliates | $ **7,710** | 8,453 | 9,340 |
| | | | |
| **Total Assets** | | | |
| Alaska | $ **14,623** | 15,453 | 14,648 |
| Lower 48 | **11,932** | 14,425 | 14,888 |
| Canada | **6,863** | 6,350 | 5,748 |
| Europe, Middle East and North Africa | **8,756** | 9,269 | 11,276 |
| Asia Pacific | **11,231** | 13,568 | 14,758 |
| Other International | **226** | 285 | 89 |
| Corporate and Other | **8,987** | 11,164 | 8,573 |
| Consolidated total assets | $ **62,618** | 70,514 | 69,980 |
| | | | |
| **Capital Expenditures and Investments** | | | |
| Alaska | $ **1,038** | 1,513 | 1,298 |
| Lower 48 | **1,881** | 3,394 | 3,184 |
| Canada | **651** | 368 | 477 |
| Europe, Middle East and North Africa | **600** | 708 | 877 |
| Asia Pacific | **384** | 584 | 718 |
| Other International | **121** | 8 | 6 |
| Corporate and Other | **40** | 61 | 190 |
| Consolidated capital expenditures and investments | $ **4,715** | 6,636 | 6,750 |
| | | | |
| **Interest Income and Expense** | | | |
| Interest income | | | |
| Alaska | $ **-** | - | - |
| Lower 48 | **-** | - | - |
| Canada | **-** | - | - |
| Europe, Middle East and North Africa | **5** | 11 | 12 |
| Asia Pacific | **7** | 6 | 5 |
| Other International | **-** | - | - |
| Corporate and Other | **88** | 149 | 80 |
| Interest and debt expense | | | |
| Corporate and Other | $ **806** | 778 | 735 |
| | | | |
| **Sales and Other Operating Revenues by Product** | | | |
| Crude oil | $ **9,736** | 18,482 | 19,571 |
| Natural gas | **6,427** | 8,715 | 10,720 |
| Natural gas liquids | **528** | 814 | 1,114 |
| Other* | **2,093** | 4,556 | 5,012 |
| Consolidated sales and other operating revenues by product | $ **18,784** | 32,567 | 36,417 |

**Includes LNG and bitumen.*

**Geographic Information**

| | Millions of Dollars | | | | | |
|---|---|---|---|---|---|---|
| | Sales and Other Operating Revenues[(1)] | | | Long-Lived Assets[(2)] | | |
| | **2020** | 2019 | 2018 | **2020** | 2019 | 2018 |
| United States | $ **13,230** | 21,159 | 22,740 | **24,034** | 26,566 | 26,838 |
| Australia and Timor-Leste | **605** | 1,647 | 1,798 | **6,676** | 7,228 | 9,301 |
| Canada | **1,261** | 1,769 | 2,024 | **6,385** | 5,769 | 5,333 |
| China | **460** | 772 | 836 | **1,491** | 1,447 | 1,380 |
| Indonesia | **689** | 875 | 886 | **464** | 605 | 669 |
| Libya | **155** | 1,103 | 1,142 | **670** | 668 | 679 |
| Malaysia | **610** | 1,230 | 1,346 | **1,501** | 1,871 | 2,327 |
| Norway | **1,426** | 2,349 | 2,886 | **5,294** | 5,258 | 5,582 |
| United Kingdom | **336** | 1,649 | 2,606 | **1** | 2 | 1,583 |
| Other foreign countries | **12** | 14 | 153 | **1,087** | 1,308 | 1,346 |
| Worldwide consolidated | $ **18,784** | 32,567 | 36,417 | **47,603** | 50,722 | 55,038 |

*(1) Sales and other operating revenues are attributable to countries based on the location of the selling operation.*
*(2) Defined as net PP&E plus equity investments and advances to affiliated companies.*

**Note 25—Acquisition of Concho Resources Inc.**

On October 18, 2020, we entered into a definitive agreement to acquire Concho in an all-stock transaction. The transaction closed on January 15, 2021 and as defined under the terms of the transaction agreement, each share of Concho common stock was exchanged at a fixed ratio of 1.46 for shares of ConocoPhillips common stock, for total consideration of $13.1 billion. This resulted in issuance of 286 million shares, representing approximately 21 percent of the outstanding shares of ConocoPhillips common stock upon completion of the transaction.

We also assumed Concho's outstanding debt of $3.9 billion in aggregate principal amount, recorded at fair value of $4.7 billion on the transaction closing date. On December 7, 2020, we launched a debt exchange offer which settled on February 8, 2021, for 98 percent of Concho's historical notes. The historical notes issued by Concho were exchanged for new notes issued by ConocoPhillips, which are fully and unconditionally guaranteed by ConocoPhillips Company. For further discussion about the debt exchange, see Note 10 – Debt.

As of the acquisition date, January 15, 2021, the fair value of consideration transferred is summarized below:

**Total Consideration**

| | | |
|---|---|---|
| Number of shares of Concho common stock issued and outstanding (in thousands)* | | 194,243 |
| 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.*

The transaction will be accounted for as a business combination under the acquisition method of accounting. The total purchase price will be allocated to identifiable assets acquired and the liabilities assumed based on their fair values as of the closing date. We are currently in the process of finalizing the initial accounting for this transaction and provisional fair value measurements will be made in the first quarter of 2021. We may adjust the measurements in subsequent periods, up to one year from the acquisition date as we identify additional information to complete the necessary analysis.

---

**Oil and Gas Operations** (Unaudited)

In accordance with FASB ASC Topic 932, "Extractive Activities—Oil and Gas," and regulations of the SEC, we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate 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, 2020, approximately 6 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 8 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

**Reserves Governance**

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

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

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

During 2020, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2020, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material 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, 2020, 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 2017 | 937 | 707 | 1,644 | 1 | 296 | 185 | 196 | 2,322 |
| Revisions | 72 | (90) | (18) | 2 | 24 | 6 | 5 | 19 |
| Improved recovery | 2 | - | 2 | - | - | - | - | 2 |
| Purchases | 233 | 1 | 234 | - | - | - | - | 234 |
| Extensions and discoveries | 48 | 179 | 227 | 2 | 2 | 1 | - | 232 |
| Production | (59) | (82) | (141) | (1) | (40) | (33) | (13) | (228) |
| Sales | - | (12) | (12) | - | (36) | - | - | (48) |
| End of 2018 | 1,233 | 703 | 1,936 | 4 | 246 | 159 | 188 | 2,533 |
| Revisions | 40 | (36) | 4 | (1) | 18 | (5) | 23 | 39 |
| Improved recovery | 7 | - | 7 | - | - | - | - | 7 |
| Purchases | - | 1 | 1 | - | - | - | - | 1 |
| Extensions and discoveries | 25 | 226 | 251 | 2 | - | 11 | - | 264 |
| Production | (74) | (95) | (169) | - | (36) | (31) | (14) | (250) |
| Sales | - | (2) | (2) | - | (30) | - | - | (32) |
| End of 2019 | 1,231 | 797 | 2,028 | 5 | 198 | 134 | 197 | 2,562 |
| 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 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 83 | - | 83 |
| Revisions | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (5) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2018 | - | - | - | - | - | 78 | - | 78 |
| Revisions | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (5) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2019 | - | - | - | - | - | 73 | - | 73 |
| Revisions | - | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (5) | - | (5) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2020** | - | - | - | - | - | 68 | - | 68 |
| *Total company* | | | | | | | | |
| End of 2017 | 937 | 707 | 1,644 | 1 | 296 | 268 | 196 | 2,405 |
| End of 2018 | 1,233 | 703 | 1,936 | 4 | 246 | 237 | 188 | 2,611 |
| End of 2019 | 1,231 | 797 | 2,028 | 5 | 198 | 207 | 197 | 2,635 |
| **End of 2020** | 879 | 693 | 1,572 | 6 | 174 | 176 | 191 | 2,119 |

| 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 2017 | 828 | 315 | 1,143 | 1 | 190 | 121 | 196 | 1,651 |
| End of 2018 | 1,058 | 346 | 1,404 | 2 | 192 | 113 | 185 | 1,896 |
| End of 2019 | 1,048 | 334 | 1,382 | 3 | 149 | 94 | 181 | 1,809 |
| **End of 2020** | 765 | 263 | 1,028 | 6 | 129 | 77 | 175 | 1,415 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 83 | - | 83 |
| End of 2018 | - | - | - | - | - | 78 | - | 78 |
| End of 2019 | - | - | - | - | - | 73 | - | 73 |
| **End of 2020** | - | - | - | - | - | 68 | - | 68 |
| **Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2017 | 109 | 392 | 501 | - | 106 | 64 | - | 671 |
| End of 2018 | 175 | 357 | 532 | 2 | 54 | 46 | 3 | 637 |
| End of 2019 | 183 | 463 | 646 | 2 | 49 | 40 | 16 | 753 |
| **End of 2020** | 114 | 430 | 544 | - | 45 | 31 | 16 | 636 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | - | - | - |
| End of 2018 | - | - | - | - | - | - | - | - |
| End of 2019 | - | - | - | - | - | - | - | - |
| **End of 2020** | - | - | - | - | - | - | - | - |

Notable changes in proved crude oil reserves in the three years ended December 31, 2020, included:

- *Revisions*: In 2020, Alaska downward revisions were primarily driven by lower prices of 243 million barrels 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.

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to development timing were partially offset by higher prices. Revisions in Alaska, Europe and Asia Pacific/Middle East were primarily due to higher prices.

- *Purchases:* In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acquisitions.

- *Extensions and discoveries*: In 2020, extensions and discoveries in Lower 48 were due to planned 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.

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays. Extensions and discoveries in Alaska were driven by drilling success in Western North Slope.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Europe sales were due to the disposition of a subsidiary that held 16.5 percent of our 24 percent interest in the Clair Field in the U.K.

| 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 2017 | 106 | 224 | 330 | 1 | 18 | 5 | 354 |
| Revisions | 5 | (25) | (20) | - | 1 | (1) | (20) |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 69 | 69 | - | 1 | - | 70 |
| Production | (5) | (25) | (30) | - | (3) | (1) | (34) |
| Sales | - | (21) | (21) | - | - | - | (21) |
| End of 2018 | 106 | 222 | 328 | 1 | 17 | 3 | 349 |
| Revisions | (1) | (11) | (12) | - | 3 | (1) | (10) |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | 62 | 62 | 1 | - | - | 63 |
| Production | (5) | (28) | (33) | - | (3) | (1) | (37) |
| Sales | - | - | - | - | (4) | - | (4) |
| End of 2019 | 100 | 245 | 345 | 2 | 13 | 1 | 361 |
| 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 |
| | | | | | | | |
| *Equity affiliates* | | | | | | | |
| End of 2017 | - | - | - | - | - | 45 | 45 |
| Revisions | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | (3) |
| Sales | - | - | - | - | - | - | - |
| End of 2018 | - | - | - | - | - | 42 | 42 |
| Revisions | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | (3) |
| Sales | - | - | - | - | - | - | - |
| End of 2019 | - | - | - | - | - | 39 | 39 |
| Revisions | - | - | - | - | - | - | - |
| Improved recovery | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | - | - |
| Production | - | - | - | - | - | (3) | (3) |
| Sales | - | - | - | - | - | - | - |
| **End of 2020** | - | - | - | - | - | 36 | 36 |
| | | | | | | | |
| *Total company* | | | | | | | |
| End of 2017 | 106 | 224 | 330 | 1 | 18 | 50 | 399 |
| End of 2018 | 106 | 222 | 328 | 1 | 17 | 45 | 391 |
| End of 2019 | 100 | 245 | 345 | 2 | 13 | 40 | 400 |
| **End of 2020** | 94 | 230 | 324 | 4 | 12 | 36 | 376 |

| 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 2017 | 106 | 101 | 207 | 1 | 16 | 2 | 226 |
| End of 2018 | 106 | 97 | 203 | - | 15 | 3 | 221 |
| End of 2019 | 100 | 99 | 199 | 1 | 10 | 1 | 211 |
| **End of 2020** | 94 | 83 | 177 | 4 | 9 | - | 190 |
| *Equity affiliates* | | | | | | | |
| End of 2017 | - | - | - | - | - | 45 | 45 |
| End of 2018 | - | - | - | - | - | 42 | 42 |
| End of 2019 | - | - | - | - | - | 39 | 39 |
| **End of 2020** | - | - | - | - | - | 36 | 36 |
| **Undeveloped** | | | | | | | |
| *Consolidated operations* | | | | | | | |
| End of 2017 | - | 123 | 123 | - | 2 | 3 | 128 |
| End of 2018 | - | 125 | 125 | 1 | 2 | - | 128 |
| End of 2019 | - | 146 | 146 | 1 | 3 | - | 150 |
| **End of 2020** | - | 147 | 147 | - | 3 | - | 150 |
| *Equity affiliates* | | | | | | | |
| End of 2017 | - | - | - | - | - | - | - |
| End of 2018 | - | - | - | - | - | - | - |
| End of 2019 | - | - | - | - | - | - | - |
| **End of 2020** | - | - | - | - | - | - | - |

Notable changes in proved NGL reserves in the three years ended December 31, 2020, included:

- *Revisions*: In 2020, downward revisions in Lower 48 were due to lower prices of 33 million barrels and 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.

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category.

- *Extensions and discoveries*: 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.

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Lower 48 sales were primarily due to the disposition of our interests in the Barnett.

| 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 2017 | 2,320 | 2,533 | 4,853 | 11 | 1,217 | 1,298 | 224 | 7,603 |
| Revisions | 150 | (283) | (133) | 9 | 86 | 4 | - | (34) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | 335 | 1 | 336 | - | - | - | - | 336 |
| Extensions and discoveries | 2 | 527 | 529 | 11 | 110 | 23 | - | 673 |
| Production | (71) | (237) | (308) | (5) | (188) | (246) | (10) | (757) |
| Sales | - | (223) | (223) | - | (13) | - | - | (236) |
| End of 2018 | 2,736 | 2,318 | 5,054 | 26 | 1,212 | 1,079 | 214 | 7,585 |
| Revisions | 30 | (113) | (83) | (2) | 160 | 147 | 21 | 243 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | 2 | 2 | - | - | - | - | 2 |
| Extensions and discoveries | 7 | 483 | 490 | 23 | - | 1 | - | 514 |
| Production | (85) | (252) | (337) | (4) | (178) | (250) | (11) | (780) |
| Sales | - | (7) | (7) | - | (298) | - | - | (305) |
| End of 2019 | 2,688 | 2,431 | 5,119 | 43 | 896 | 977 | 224 | 7,259 |
| 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 |
| | | | | | | | | |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 4,303 | - | 4,303 |
| Revisions | - | - | - | - | - | 280 | - | 280 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 362 | - | 362 |
| Production | - | - | - | - | - | (381) | - | (381) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2018 | - | - | - | - | - | 4,564 | - | 4,564 |
| Revisions | - | - | - | - | - | (7) | - | (7) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 252 | - | 252 |
| Production | - | - | - | - | - | (388) | - | (388) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2019 | - | - | - | - | - | 4,421 | - | 4,421 |
| Revisions | - | - | - | - | - | (382) | - | (382) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | 2 | - | 2 |
| Extensions and discoveries | - | - | - | - | - | 78 | - | 78 |
| Production | - | - | - | - | - | (395) | - | (395) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2020** | - | - | - | - | - | 3,724 | - | 3,724 |
| | | | | | | | | |
| *Total company* | | | | | | | | |
| End of 2017 | 2,320 | 2,533 | 4,853 | 11 | 1,217 | 5,601 | 224 | 11,906 |
| End of 2018 | 2,736 | 2,318 | 5,054 | 26 | 1,212 | 5,643 | 214 | 12,149 |
| End of 2019 | 2,688 | 2,431 | 5,119 | 43 | 896 | 5,398 | 224 | 11,680 |
| **End of 2020** | 1,996 | 2,100 | 4,096 | 74 | 825 | 4,575 | 224 | 9,794 |

| 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 2017 | 2,310 | 1,597 | 3,907 | 11 | 997 | 945 | 224 | 6,084 |
| End of 2018 | 2,720 | 1,427 | 4,147 | 17 | 1,052 | 758 | 214 | 6,188 |
| End of 2019 | 2,601 | 1,398 | 3,999 | 30 | 697 | 843 | 224 | 5,793 |
| **End of 2020** | 1,961 | 1,051 | 3,012 | 74 | 598 | 806 | 224 | 4,714 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 4,044 | - | 4,044 |
| End of 2018 | - | - | - | - | - | 4,059 | - | 4,059 |
| End of 2019 | - | - | - | - | - | 3,898 | - | 3,898 |
| **End of 2020** | - | - | - | - | - | 3,293 | - | 3,293 |
| **Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2017 | 10 | 936 | 946 | - | 220 | 353 | - | 1,519 |
| End of 2018 | 16 | 891 | 907 | 9 | 160 | 321 | - | 1,397 |
| End of 2019 | 87 | 1,033 | 1,120 | 13 | 199 | 134 | - | 1,466 |
| **End of 2020** | 35 | 1,049 | 1,084 | - | 227 | 45 | - | 1,356 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 259 | - | 259 |
| End of 2018 | - | - | - | - | - | 505 | - | 505 |
| End of 2019 | - | - | - | - | - | 523 | - | 523 |
| **End of 2020** | - | - | - | - | - | 431 | - | 431 |

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 2,286 Bcf, 3,141 Bcf, and 3,131 Bcf as of December 31, 2020, 2019 and 2018, 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, 2020, included:

- *Revisions*: 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.

In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category.  Downward revisions in Lower 48 due to development timing were partially offset by higher prices.  Revisions in Alaska, Canada, Europe and our equity affiliates in Asia Pacific/Middle East were primarily due to higher prices.

- *Purchases*: In 2020, Canada purchases were due to the acquisition of additional Montney acreage.

  In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acquisitions.

- *Extensions and discoveries*: In 2020, extensions and discoveries in Lower 48 were due to planned 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.

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays.  Extensions and discoveries in Canada, Europe and our equity affiliates in Asia Pacific/Middle East were primarily driven by ongoing drilling successes in Montney, Norway and APLNG, respectively.

- *Sales*: In 2020, Asia Pacific/Middle East sales represent the disposition of the Australia-West assets.

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

  In 2018, Lower 48 sales were primarily due to the disposition of our interest in Barnett.

| Years Ended December 31 | Bitumen |
| --- | --- |
| | Millions of Barrels |
| | Canada |
| **Developed and Undeveloped** | |
| *Consolidated operations* | |
| End of 2017 | 250 |
| Revisions | 10 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | (24) |
| Sales | - |
| End of 2018 | 236 |
| Revisions | 37 |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 31 |
| Production | (22) |
| Sales | - |
| End of 2019 | 282 |
| Revisions | (15) |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | 85 |
| Production | (20) |
| Sales | - |
| **End of 2020** | 332 |
| *Equity affiliates* | |
| End of 2017 | - |
| Revisions | - |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | - |
| Sales | - |
| End of 2018 | - |
| Revisions | - |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | - |
| Sales | - |
| End of 2019 | - |
| Revisions | - |
| Improved recovery | - |
| Purchases | - |
| Extensions and discoveries | - |
| Production | - |
| Sales | - |
| **End of 2020** | - |
| *Total company* | |
| End of 2017 | 250 |
| End of 2018 | 236 |
| End of 2019 | 282 |
| **End of 2020** | 332 |

| Years Ended December 31 | **Bitumen** Millions of Barrels Canada |
|---|---|
| **Developed** | |
| *Consolidated operations* | |
| End of 2017 | 154 |
| End of 2018 | 155 |
| End of 2019 | 187 |
| **End of 2020** | 117 |
| *Equity affiliates* | |
| End of 2017 | - |
| End of 2018 | - |
| End of 2019 | - |
| **End of 2020** | - |
| **Undeveloped** | |
| *Consolidated operations* | |
| End of 2017 | 96 |
| End of 2018 | 81 |
| End of 2019 | 95 |
| **End of 2020** | 215 |
| *Equity affiliates* | |
| End of 2017 | - |
| End of 2018 | - |
| End of 2019 | - |
| **End of 2020** | - |

Notable changes in proved bitumen reserves in the three years ended December 31, 2020, included:

- *Revisions*: In 2020, downward revisions in Canada were due to changes in development timing for specific pad locations from the Surmont development program of 12 million barrels with the remaining revisions primarily related to lower prices.

  In 2019, upward revisions in Canada were due to technical revisions in Surmont of 70 million barrels, partially offset by downward revisions due to changes in development timing for specific pad locations from the Surmont development program of 31 million barrels.

  In 2018, revisions were primarily due to higher prices at Surmont.

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

  In 2019, extensions and discoveries in Canada were due to planned development to add specific pad locations from the Surmont development program, which offset the decrease in the revisions 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 2017 | 1,430 | 1,353 | 2,783 | 254 | 517 | 406 | 233 | 4,193 |
| Revisions | 102 | (161) | (59) | 12 | 40 | 5 | 6 | 4 |
| Improved recovery | 2 | - | 2 | - | - | - | - | 2 |
| Purchases | 289 | 1 | 290 | - | - | - | - | 290 |
| Extensions and discoveries | 48 | 335 | 383 | 4 | 21 | 6 | - | 414 |
| Production | (76) | (146) | (222) | (25) | (75) | (75) | (15) | (412) |
| Sales | - | (70) | (70) | - | (38) | - | - | (108) |
| End of 2018 | 1,795 | 1,312 | 3,107 | 245 | 465 | 342 | 224 | 4,383 |
| Revisions | 44 | (67) | (23) | 36 | 48 | 19 | 26 | 106 |
| Improved recovery | 7 | - | 7 | - | - | - | - | 7 |
| Purchases | - | 2 | 2 | - | - | - | - | 2 |
| Extensions and discoveries | 26 | 368 | 394 | 38 | - | 11 | - | 443 |
| Production | (93) | (165) | (258) | (23) | (68) | (74) | (16) | (439) |
| Sales | - | (3) | (3) | - | (85) | - | - | (88) |
| End of 2019 | 1,779 | 1,447 | 3,226 | 296 | 360 | 298 | 234 | 4,414 |
| 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 |
| | | | | | | | | |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 845 | - | 845 |
| Revisions | - | - | - | - | - | 46 | - | 46 |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 60 | - | 60 |
| Production | - | - | - | - | - | (71) | - | (71) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2018 | - | - | - | - | - | 880 | - | 880 |
| Revisions | - | - | - | - | - | (1) | - | (1) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 42 | - | 42 |
| Production | - | - | - | - | - | (73) | - | (73) |
| Sales | - | - | - | - | - | - | - | - |
| End of 2019 | - | - | - | - | - | 848 | - | 848 |
| Revisions | - | - | - | - | - | (63) | - | (63) |
| Improved recovery | - | - | - | - | - | - | - | - |
| Purchases | - | - | - | - | - | - | - | - |
| Extensions and discoveries | - | - | - | - | - | 13 | - | 13 |
| Production | - | - | - | - | - | (73) | - | (73) |
| Sales | - | - | - | - | - | - | - | - |
| **End of 2020** | - | - | - | - | - | 725 | - | 725 |
| | | | | | | | | |
| *Total company* | | | | | | | | |
| End of 2017 | 1,430 | 1,353 | 2,783 | 254 | 517 | 1,251 | 233 | 5,038 |
| End of 2018 | 1,795 | 1,312 | 3,107 | 245 | 465 | 1,222 | 224 | 5,263 |
| End of 2019 | 1,779 | 1,447 | 3,226 | 296 | 360 | 1,146 | 234 | 5,262 |
| **End of 2020** | 1,306 | 1,273 | 2,579 | 355 | 323 | 974 | 228 | 4,459 |

| 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 2017 | 1,319 | 682 | 2,001 | 158 | 372 | 281 | 233 | 3,045 |
| End of 2018 | 1,617 | 681 | 2,298 | 160 | 382 | 244 | 221 | 3,305 |
| End of 2019 | 1,582 | 666 | 2,248 | 197 | 275 | 236 | 218 | 3,174 |
| **End of 2020** | 1,186 | 521 | 1,707 | 140 | 238 | 211 | 212 | 2,508 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 802 | - | 802 |
| End of 2018 | - | - | - | - | - | 796 | - | 796 |
| End of 2019 | - | - | - | - | - | 761 | - | 761 |
| **End of 2020** | - | - | - | - | - | 653 | - | 653 |
| **Undeveloped** | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| End of 2017 | 111 | 671 | 782 | 96 | 145 | 125 | - | 1,148 |
| End of 2018 | 178 | 631 | 809 | 85 | 83 | 98 | 3 | 1,078 |
| End of 2019 | 197 | 781 | 978 | 99 | 85 | 62 | 16 | 1,240 |
| **End of 2020** | 120 | 752 | 872 | 215 | 85 | 38 | 16 | 1,226 |
| *Equity affiliates* | | | | | | | | |
| End of 2017 | - | - | - | - | - | 43 | - | 43 |
| End of 2018 | - | - | - | - | - | 84 | - | 84 |
| End of 2019 | - | - | - | - | - | 87 | - | 87 |
| **End of 2020** | - | - | - | - | - | 72 | - | 72 |

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 2020:

| | **Proved Undeveloped Reserves** |
|---|---|
| | Millions of Barrels of Oil Equivalent |
| End of 2019 | 1,327 |
| Revisions | (205) |
| Improved recovery | 3 |
| Purchases | 7 |
| Extensions and discoveries | 304 |
| Sales | - |
| Transfers to proved developed | (138) |
| **End of 2020** | 1,298 |

Downward revisions were driven by changes in development timing of 137 MMBOE primarily in North America and lower prices of 103 MMBOE, partially offset by upward revisions for infill drilling of 35 MMBOE primarily in Lower 48 and Europe.

Extensions and discoveries were largely driven by an addition of 196 MMBOE in Lower 48 for the continued development of unconventional plays. The remaining extensions and discoveries were driven by the continued development planned in Canada, Asia Pacific/Middle East and Alaska.

Transfers to proved developed reserves were driven by the ongoing development of our assets. Approximately half of the transfers were from the development of our Lower 48 unconventional plays. The remainder of transfers were from development across the Alaska, Asia Pacific/Middle East and Europe regions.

At December 31, 2020, our PUDs represented 29 percent of total proved reserves, compared with 25 percent at December 31, 2019. Costs incurred for the year ended December 31, 2020, relating to the development of PUDs were $3.2 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 2020, more than 97 percent of total PUDs were under development or scheduled for development within five years of initial disclosure, including our PUDs in North America. The remaining PUDs are in major development areas which are currently producing and within our Asia Pacific/Middle East geographic area.

**Results of Operations**

The company's results of operations from oil and gas activities for the years 2020, 2019 and 2018 are shown in the 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, 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 |

| Year Ended December 31, 2018 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| *Consolidated operations* | | | | | | | | | |
| Sales | $ 4,816 | 6,573 | 11,389 | 582 | 4,449 | 3,177 | 950 | - | 20,547 |
| Transfers | 5 | - | 5 | - | - | 545 | - | - | 550 |
| Transportation costs | (722) | - | (722) | - | - | (45) | - | - | (767) |
| Other revenues | 335 | 213 | 548 | 164 | 737 | 6 | 110 | 432 | 1,997 |
| Total revenues | 4,434 | 6,786 | 11,220 | 746 | 5,186 | 3,683 | 1,060 | 432 | 22,327 |
| Production costs excluding taxes | 964 | 1,533 | 2,497 | 417 | 856 | 646 | 62 | 2 | 4,480 |
| Taxes other than income taxes | 357 | 432 | 789 | 21 | 33 | 95 | 3 | - | 941 |
| Exploration expenses | 59 | 176 | 235 | 21 | 57 | 43 | (4) | 20 | 372 |
| Depreciation, depletion and amortization | 616 | 2,279 | 2,895 | 313 | 1,070 | 1,186 | 33 | - | 5,497 |
| Impairments | 1 | 64 | 65 | 9 | (78) | 14 | - | - | 10 |
| Other related expenses | 16 | 63 | 79 | 56 | (62) | (19) | 1 | (1) | 54 |
| Accretion | 56 | 51 | 107 | 7 | 178 | 39 | - | - | 331 |
| | 2,365 | 2,188 | 4,553 | (98) | 3,132 | 1,679 | 965 | 411 | 10,642 |
| Income tax provision (benefit) | 419 | 466 | 885 | (114) | 1,354 | 683 | 926 | (8) | 3,726 |
| Results of operations | $ 1,946 | 1,722 | 3,668 | 16 | 1,778 | 996 | 39 | 419 | 6,916 |
| | | | | | | | | | |
| *Equity affiliates* | | | | | | | | | |
| Sales | $ - | - | - | - | - | 758 | - | - | 758 |
| Transfers | - | - | - | - | - | 2,018 | - | - | 2,018 |
| Transportation costs | - | - | - | - | - | - | - | - | - |
| Other revenues | - | - | - | - | - | (6) | - | - | (6) |
| Total revenues | - | - | - | - | - | 2,770 | - | - | 2,770 |
| Production costs excluding taxes | - | - | - | - | - | 321 | - | - | 321 |
| Taxes other than income taxes | - | - | - | - | - | 804 | - | - | 804 |
| Exploration expenses | - | - | - | - | - | - | - | - | - |
| Depreciation, depletion and | | | | - | - | - | - | | |
| amortization | - | - | - | - | - | 640 | - | - | 640 |
| Impairments | - | - | - | - | - | - | - | - | - |
| Other related expenses | - | - | - | - | - | (4) | - | - | (4) |
| Accretion | - | - | - | - | - | 15 | - | - | 15 |
| | - | - | - | - | - | 994 | - | - | 994 |
| Income tax provision (benefit) | - | - | - | - | - | 103 | - | - | 103 |
| Results of operations | $ - | - | - | - | - | 891 | - | - | 891 |

## Statistics

| **Net Production** | **2020** | 2019 | 2018 |
|---|---|---|---|
| | Thousands of Barrels Daily | | |
| **Crude Oil** | | | |
| *Consolidated operations* | | | |
| Alaska | **181** | 202 | 171 |
| Lower 48 | **213** | 266 | 229 |
| United States | **394** | 468 | 400 |
| Canada | **6** | 1 | 1 |
| Europe | **78** | 100 | 113 |
| Asia Pacific | **69** | 85 | 89 |
| Africa | **8** | 38 | 36 |
| Total consolidated operations | **555** | 692 | 639 |
| *Equity affiliates*—Asia Pacific/Middle East | **13** | 13 | 14 |
| Total company | **568** | 705 | 653 |
| *Greater Prudhoe Area (Alaska)** | ***68*** | *66* | *71* |
| **Natural Gas Liquids** | | | |
| *Consolidated operations* | | | |
| Alaska | **16** | 15 | 14 |
| Lower 48 | **74** | 81 | 69 |
| United States | **90** | 96 | 83 |
| Canada | **2** | - | 1 |
| Europe | **4** | 7 | 8 |
| Asia Pacific | **1** | 4 | 3 |
| Total consolidated operations | **97** | 107 | 95 |
| *Equity affiliates*—Asia Pacific/Middle East | **8** | 8 | 7 |
| Total company | **105** | 115 | 102 |
| *Greater Prudhoe Area (Alaska)** | ***15*** | *15* | *14* |
| **Bitumen** | | | |
| *Consolidated operations*—Canada | **55** | 60 | 66 |
| Total company | **55** | 60 | 66 |
| **Natural Gas** | Millions of Cubic Feet Daily | | |
| *Consolidated operations* | | | |
| Alaska | **10** | 7 | 6 |
| Lower 48 | **585** | 622 | 596 |
| United States | **595** | 629 | 602 |
| Canada | **40** | 9 | 12 |
| Europe | **270** | 447 | 475 |
| Asia Pacific | **429** | 637 | 626 |
| Africa | **5** | 31 | 28 |
| Total consolidated operations | **1,339** | 1,753 | 1,743 |
| *Equity affiliates*—Asia Pacific/Middle East | **1,055** | 1,052 | 1,031 |
| Total company | **2,394** | 2,805 | 2,774 |
| *Greater Prudhoe Area (Alaska)** | ***4*** | *4* | *5* |

**At year-end 2020 and 2019, the Greater Prudhoe Area in Alaska contained more than 15 percent of our total proved reserves.*

| Average Sales Prices | | 2020 | 2019 | 2018 |
|---|---|---|---|---|
| **Crude Oil Per Barrel** | | | | |
| *Consolidated operations* | | | | |
| Alaska* | $ | **33.72** | 55.85 | 60.23 |
| Lower 48 | | **35.17** | 55.30 | 62.99 |
| United States | | **34.48** | 55.54 | 61.75 |
| Canada | | **23.57** | 40.87 | 48.73 |
| Europe | | **42.80** | 65.12 | 70.98 |
| Asia Pacific | | **42.84** | 65.02 | 70.93 |
| Africa | | **48.64** | 64.47 | 69.83 |
| Total international | | **42.39** | 64.85 | 70.67 |
| Total consolidated operations | | **36.69** | 58.51 | 65.01 |
| *Equity affiliates*—Asia Pacific/Middle East | | **39.02** | 61.32 | 72.49 |
| Total operations | | **36.75** | 58.57 | 65.17 |
| **Natural Gas Liquids Per Barrel** | | | | |
| *Consolidated operations* | | | | |
| Lower 48 | $ | **12.13** | 16.83 | 27.30 |
| United States | | **12.13** | 16.85 | 27.30 |
| Canada | | **5.41** | 19.87 | 43.70 |
| Europe | | **23.27** | 29.37 | 36.87 |
| Asia Pacific | | **33.21** | 37.85 | 47.20 |
| Total international | | **20.25** | 32.29 | 40.00 |
| Total consolidated operations | | **12.90** | 18.73 | 29.03 |
| *Equity affiliates*—Asia Pacific/Middle East | | **32.69** | 36.70 | 45.69 |
| Total operations | | **14.61** | 20.09 | 30.48 |
| **Bitumen Per Barrel** | | | | |
| *Consolidated operations*—Canada | $ | **8.02** ** | 31.72 | 22.29 |
| **Natural Gas Per Thousand Cubic Feet** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **2.91** | 3.19 | 2.48 |
| Lower 48 | | **1.65** | 2.12 | 2.82 |
| United States | | **1.66** | 2.12 | 2.82 |
| Canada | | **1.21** | 0.49 | 1.00 |
| Europe | | **3.23** | 4.92 | 7.79 |
| Asia Pacific* | | **5.27** | 5.73 | 5.95 |
| Africa | | **3.71** | 4.87 | 4.84 |
| Total international | | **4.31** | 5.35 | 6.64 |
| Total consolidated operations | | **3.13** | 4.19 | 5.33 |
| *Equity affiliates*—Asia Pacific/Middle East | | **3.71** | 6.29 | 6.06 |
| Total operations | | **3.38** | 4.99 | 5.60 |

**Average sales prices for Alaska crude oil and Asia Pacific natural gas above reflect a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results of Operations.*
***Average sales prices include unutilized transportation costs.*

| | | 2020 | 2019 | 2018 |
|---|---|---|---|---|
| **Average Production Costs Per Barrel of Oil Equivalent*** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **14.60** | 15.52 | 14.20 |
| Lower 48 | | **9.93** | 9.59 | 10.58 |
| United States | | **11.51** | 11.52 | 11.73 |
| Canada | | **14.29** | 16.53 | 16.32 |
| Europe | | **8.97** | 11.22 | 11.73 |
| Asia Pacific | | **9.26** | 8.74 | 9.03 |
| Africa | | **6.38** | 4.46 | 4.14 |
| Total international | | **10.11** | 10.26 | 10.72 |
| Total consolidated operations | | **10.99** | 10.99 | 11.26 |
| *Equity affiliates*—Asia Pacific/Middle East | | **4.01** | 4.68 | 4.56 |
| **Average Production Costs Per Barrel—Bitumen** | | | | |
| *Consolidated operations*—Canada | $ | **12.45** | 13.74 | 13.59 |
| **Taxes Other Than Income Taxes Per Barrel of Oil Equivalent** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **4.08** | 3.87 | 5.26 |
| Lower 48 | | **1.87** | 2.65 | 2.98 |
| United States | | **2.62** | 3.05 | 3.71 |
| Canada | | **0.62** | 0.78 | 0.82 |
| Europe | | **0.65** | 0.48 | 0.45 |
| Asia Pacific | | **0.81** | 0.76 | 1.33 |
| Africa | | **0.91** | 0.19 | 0.20 |
| Total international | | **0.72** | 0.60 | 0.82 |
| Total consolidated operations | | **1.91** | 2.03 | 2.37 |
| *Equity affiliates*—Asia Pacific/Middle East | | **6.96** | 11.46 | 11.41 |
| **Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent** | | | | |
| *Consolidated operations* | | | | |
| Alaska | $ | **11.59** | 8.80 | 9.07 |
| Lower 48 | | **18.05** | 17.03 | 15.73 |
| United States | | **15.86** | 14.35 | 13.60 |
| Canada | | **13.08** | 10.00 | 12.25 |
| Europe | | **16.24** | 12.75 | 14.66 |
| Asia Pacific | | **15.66** | 16.55 | 16.58 |
| Africa | | **2.43** | 2.36 | 2.21 |
| Total international | | **15.01** | 12.99 | 14.06 |
| Total consolidated operations | | **15.54** | 13.78 | 13.82 |
| *Equity affiliates*—Asia Pacific/Middle East | | **7.89** | 8.09 | 9.09 |

**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, 2020, 2019 and 2018. A "development well" is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "exploratory well" is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and CBM test wells located in Asia Pacific/Middle East.

**Net Wells Completed**

| | Productive | | | Dry | | |
|---|---|---|---|---|---|---|
| | **2020** | 2019 | 2018 | **2020** | 2019 | 2018 |
| **Exploratory** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **-** | 7 | 6 | **3** | - | - |
| Lower 48 | **3** | 35 | 45 | **-** | 6 | 1 |
| United States | **3** | 42 | 51 | **3** | 6 | 1 |
| Canada | **23** | - | 2 | **-** | - | - |
| Europe | **-** | 1 | * | ***** | 1 | * |
| Asia Pacific/Middle East | ***** | 1 | 2 | ***** | 1 | - |
| Africa | **-** | - | - | ***** | - | * |
| Other areas | **-** | - | - | ***** | - | - |
| Total consolidated operations | **26** | 44 | 55 | **3** | 8 | 1 |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | **8** | 8 | 6 | **-** | - | 2 |
| Total equity affiliates | **8** | 8 | 6 | **-** | - | 2 |
| **Development** | | | | | | |
| *Consolidated operations* | | | | | | |
| Alaska | **7** | 12 | 11 | **-** | - | - |
| Lower 48 | **127** | 255 | 254 | **-** | - | - |
| United States | **134** | 267 | 265 | **-** | - | - |
| Canada | **-** | 2 | 1 | **-** | - | - |
| Europe | **7** | 6 | 9 | **-** | - | - |
| Asia Pacific/Middle East | **16** | 21 | 12 | **-** | - | - |
| Africa | **2** | 2 | 1 | **-** | - | - |
| Other areas | **-** | - | - | **-** | - | - |
| Total consolidated operations | **159** | 298 | 288 | **-** | - | - |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | **109** | 106 | 75 | **-** | - | - |
| Total equity affiliates | **109** | 106 | 75 | **-** | - | - |

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2020, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2020.

**Wells at December 31, 2020**

| | | | Productive | | | |
|---|---|---|---|---|---|---|
| | In Progress | | Oil | | Gas | |
| | Gross | Net | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | | | |
| Alaska | 5 | 5 | 1,576 | 946 | - | - |
| Lower 48 | 459 | 240 | 9,382 | 4,149 | 4,182 | 1,678 |
| United States | 464 | 245 | 10,958 | 5,095 | 4,182 | 1,678 |
| Canada | 24 | 24 | 196 | 103 | 169 | 164 |
| Europe | 16 | 3 | 476 | 79 | 59 | 2 |
| Asia Pacific/Middle East | 15 | 7 | 337 | 160 | 38 | 18 |
| Africa | 7 | 1 | 850 | 139 | 10 | 2 |
| Other areas | 14 | 7 | - | - | - | - |
| Total consolidated operations | 540 | 287 | 12,817 | 5,576 | 4,458 | 1,864 |
| *Equity affiliates* | | | | | | |
| Asia Pacific/Middle East | 139 | 32 | - | - | 4,898 | 1,154 |
| Total equity affiliates | 139 | 32 | - | - | 4,898 | 1,154 |

**Acreage at December 31, 2020**

| | Thousands of Acres | | | |
|---|---|---|---|---|
| | Developed | | Undeveloped | |
| | Gross | Net | Gross | Net |
| *Consolidated operations* | | | | |
| Alaska | 659 | 472 | 1,345 | 1,336 |
| Lower 48 | 3,228 | 1,974 | 10,215 | 8,165 |
| United States | 3,887 | 2,446 | 11,560 | 9,501 |
| Canada | 293 | 214 | 3,417 | 1,946 |
| Europe | 430 | 50 | 966 | 366 |
| Asia Pacific/Middle East | 921 | 421 | 9,015 | 5,704 |
| Africa | 358 | 58 | 12,545 | 2,049 |
| Other areas | - | - | 996 | 545 |
| Total consolidated operations | 5,889 | 3,189 | 38,499 | 20,111 |
| *Equity affiliates* | | | | |
| Asia Pacific/Middle East | 1,026 | 245 | 3,820 | 860 |
| Total equity affiliates | 1,026 | 245 | 3,820 | 860 |

## 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 |
| **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 |
| 2018 | | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | | |
| Unproved property acquisition | $ | 119 | 126 | 245 | 126 | - | - | - | - | 371 |
| Proved property acquisition | | 2,227 | 16 | 2,243 | 6 | - | - | - | - | 2,249 |
| | | 2,346 | 142 | 2,488 | 132 | - | - | - | - | 2,620 |
| Exploration | | 203 | 500 | 703 | 90 | 65 | 82 | (6) | 41 | 975 |
| Development | | 718 | 2,715 | 3,433 | 301 | 703 | 773 | 16 | - | 5,226 |
| | $ | 3,267 | 3,357 | 6,624 | 523 | 768 | 855 | 10 | 41 | 8,821 |
| *Equity affiliates* | | | | | | | | | | |
| Unproved property acquisition | $ | - | - | - | - | - | - | - | - | - |
| Proved property acquisition | | - | - | - | - | - | - | - | - | - |
| | | - | - | - | - | - | - | - | - | - |
| Exploration | | - | - | - | - | - | 22 | - | - | 22 |
| Development | | - | - | - | - | - | 206 | - | - | 206 |
| | $ | - | - | - | - | - | 228 | - | - | 228 |

**Capitalized Costs**

| At December 31 | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Other Areas | Total |
| **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 |
| 2019 | | | | | | | | | |
| *Consolidated operations* | | | | | | | | | |
| Proved property | $ 20,957 | 37,491 | 58,448 | 6,673 | 14,113 | 14,566 | 924 | - | 94,724 |
| Unproved property | 1,429 | 1,055 | 2,484 | 1,149 | 87 | 501 | 123 | 290 | 4,634 |
| | 22,386 | 38,546 | 60,932 | 7,822 | 14,200 | 15,067 | 1,047 | 290 | 99,358 |
| Accumulated depreciation, depletion and amortization | 9,419 | 26,294 | 35,713 | 2,050 | 9,017 | 10,253 | 379 | 9 | 57,421 |
| | $ 12,967 | 12,252 | 25,219 | 5,772 | 5,183 | 4,814 | 668 | 281 | 41,937 |
| *Equity affiliates* | | | | | | | | | |
| Proved property | $ - | - | - | - | - | 9,996 | - | - | 9,996 |
| Unproved property | - | - | - | - | - | 2,223 | - | - | 2,223 |
| | - | - | - | - | - | 12,219 | - | - | 12,219 |
| Accumulated depreciation, depletion and amortization | - | - | - | - | - | 6,390 | - | - | 6,390 |
| | $ - | - | - | - | - | 5,829 | - | - | 5,829 |

## 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 |
| **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.

| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
|---|---|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | | | |
| 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 |

| | Alaska | Lower 48 | Total U.S. | Canada | Europe | Asia Pacific/ Middle East | Africa | Total |
|---|---|---|---|---|---|---|---|---|
| | Millions of Dollars | | | | | | | |
| 2018 | | | | | | | | |
| *Consolidated operations* | | | | | | | | |
| Future cash inflows | $ 82,072 | 56,922 | 138,994 | 6,039 | 26,989 | 16,368 | 16,434 | 204,824 |
| Less: | | | | | | | | |
| Future production costs | 42,755 | 21,363 | 64,118 | 4,099 | 8,567 | 5,705 | 1,336 | 83,825 |
| Future development costs | 10,053 | 12,136 | 22,189 | 606 | 7,608 | 1,995 | 507 | 32,905 |
| Future income tax provisions | 5,538 | 4,418 | 9,956 | - | 7,102 | 2,873 | 13,492 | 33,423 |
| Future net cash flows | 23,726 | 19,005 | 42,731 | 1,334 | 3,712 | 5,795 | 1,099 | 54,671 |
| 10 percent annual discount | 10,349 | 6,461 | 16,810 | 426 | 371 | 1,132 | 498 | 19,237 |
| Discounted future net cash flows | $ 13,377 | 12,544 | 25,921 | 908 | 3,341 | 4,663 | 601 | 35,434 |
| *Equity affiliates* | | | | | | | | |
| Future cash inflows | $ - | - | - | - | - | 33,606 | - | 33,606 |
| Less: | | | | | | | | |
| Future production costs | - | - | - | - | - | 16,449 | - | 16,449 |
| Future development costs | - | - | - | - | - | 1,228 | - | 1,228 |
| Future income tax provisions | - | - | - | - | - | 3,147 | - | 3,147 |
| Future net cash flows | - | - | - | - | - | 12,782 | - | 12,782 |
| 10 percent annual discount | - | - | - | - | - | 4,853 | - | 4,853 |
| Discounted future net cash flows | $ - | - | - | - | - | 7,929 | - | 7,929 |
| *Total company* | | | | | | | | |
| Discounted future net cash flows | $ 13,377 | 12,544 | 25,921 | 908 | 3,341 | 12,592 | 601 | 43,363 |

**Sources of Change in Discounted Future Net Cash Flows**

| | Millions of Dollars | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Consolidated Operations | | | Equity Affiliates | | | Total Company | | |
| | **2020** | 2019 | 2018 | **2020** | 2019 | 2018 | **2020** | 2019 | 2018 |
| Discounted future net cash flows at the beginning of the year | $ **27,372** | 35,434 | 20,609 | **7,170** | 7,929 | 4,395 | **34,542** | 43,363 | 25,004 |
| Changes during the year | | | | | | | | | |
| Revenues less production costs for the year | **(5,198)** | (13,424) | (14,909) | **(897)** | (1,673) | (1,651) | **(6,095)** | (15,097) | (16,560) |
| Net change in prices and production costs | **(34,307)** | (13,538) | 25,391 | **(4,769)** | (422) | 4,559 | **(39,076)** | (13,960) | 29,950 |
| Extensions, discoveries and improved recovery, less estimated future costs | **887** | 2,985 | 4,574 | **22** | 260 | 382 | **909** | 3,245 | 4,956 |
| Development costs for the year | **3,593** | 5,333 | 5,197 | **192** | 239 | 271 | **3,785** | 5,572 | 5,468 |
| Changes in estimated future development costs | **754** | 559 | (1,141) | **(205)** | (21) | 14 | **549** | 538 | (1,127) |
| Purchases of reserves in place, less estimated future costs | **1** | 10 | 3,033 | **(3)** | - | - | **(2)** | 10 | 3,033 |
| Sales of reserves in place, less estimated future costs | **(302)** | (1,997) | (1,531) | **-** | - | - | **(302)** | (1,997) | (1,531) |
| Revisions of previous quantity estimates | **(2,299)** | 2,099 | (365) | **(42)** | 69 | 62 | **(2,341)** | 2,168 | (303) |
| Accretion of discount | **3,984** | 5,144 | 3,055 | **804** | 869 | 485 | **4,788** | 6,013 | 3,540 |
| Net change in income taxes | **10,189** | 4,767 | (8,479) | **590** | (80) | (588) | **10,779** | 4,687 | (9,067) |
| Total changes | **(22,698)** | (8,062) | 14,825 | **(4,308)** | (759) | 3,534 | **(27,006)** | (8,821) | 18,359 |
| Discounted future net cash flows at year end | $ **4,674** | 27,372 | 35,434 | **2,862** | 7,170 | 7,929 | **7,536** | 34,542 | 43,363 |

- 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, 2020, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon 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, 2020.

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 81 and is incorporated herein by reference.

**Report of Independent Registered Public Accounting Firm**

This report is included in Item 8 on page 85 and is incorporated herein by reference.

## Item 9B. OTHER INFORMATION

None.

## PART III

### Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on page 33.

**Code of Business Ethics and Conduct for Directors and Employees**

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including 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 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, and is incorporated herein by reference.*

### Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, and is incorporated herein by reference.*

### Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, and is incorporated herein by reference.*

### Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, and is incorporated herein by reference.*

### Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2021, and is incorporated herein by reference.*

---

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2021 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as 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 80, are filed as part of this annual report.

2. Financial Statement Schedules

All financial statement schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 182 through 190, are filed as part of this annual report.

**CONOCOPHILLIPS**

**INDEX TO EXHIBITS**

| Exhibit Number | Description |
|---|---|
| 2.1 | Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 2.2†‡ | Purchase and Sale Agreement, dated March 29, 2017, by and among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Canada Energy Partnership, ConocoPhillips Western Canada Partnership, ConocoPhillips Canada (BRC) Partnership, ConocoPhillips Canada E&P ULC, and Cenovus Energy Inc. (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 filed by ConocoPhillips on May 4, 2017). |
| 2.3†‡ | Asset Purchase and Sale Agreement Amending Agreement, dated as of May 16, 2017, by and among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Canada Energy Partnership, ConocoPhillips Western Canada Partnership, ConocoPhillips Canada (BRC) Partnership, ConocoPhillips Canada E&P ULC, and Cenovus Energy Inc. (incorporated by reference to Exhibit 2.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 18, 2017; File No. 001-32395). |
| 2.4 | Agreement and Plan of Merger, dated as of October 18, 2020, among ConocoPhillips, Falcon Merger Sub Corp. and Concho Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 19, 2020; File No. 001-32395). |
| 3.1 | Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 3.2 | Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987). |
| 3.3 | Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 13, 2015; File No. 001-32395). |
| | ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request. |
| 4.1 | Description of Securities of the Registrant (incorporated by reference to Exhibit 4.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |

| | |
|---|---|
| 10.1 | 1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.2 | 1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.3 | Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.4 | Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 001-00720). |
| 10.5 | Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.7 | Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.8 | Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.9 | Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.10.1 | Amended and Restated ConocoPhillips Key Employee Supplemental Retirement Plan, dated January 1, 2020 (incorporate by reference to Exhibit 10.10.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |
| 10.10.2 | Eighth Amendment to Retirement Plans as amended and restated effective January 1, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2018; File No. 001-32395). |
| 10.11.1 | Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated January 1, 2020 (incorporated by reference to Exhibit 10.11.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |
| 10.11.2 | Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated January 1, 2020 (incorporated by reference to Exhibit 10.11.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |
| 10.12 | 2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |

| | |
|---|---|
| 10.15 | Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395). |
| 10.16.1 | Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521). |
| 10.16.2 | Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987). |
| 10.16.3 | Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998 (incorporated by reference to Exhibit 10.17.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.16.4 | First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999 (incorporated by reference to Exhibit 10.17.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.16.5 | Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002 (incorporated by reference to Exhibit 10.17.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.16.6 | Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006 (incorporated by reference to Exhibit 10.17.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.16.7 | Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012 (incorporated by reference to Exhibit 10.17.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.16.8 | Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015 (incorporated by reference to Exhibit 10.17.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.17.1 | ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.17.2 | First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395). |
| 10.18 | ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987). |
| 10.19.1 | Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated January 1, 2020 (incorporated by reference to Exhibit 10.19.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |

| | |
|---|---|
| 10.19.2 | Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated January 1, 2020 (incorporated by reference to Exhibit 10.19.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |
| 10.20 | Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.21 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2013; File No. 001-32395). |
| 10.21 | ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.22.1 | 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987). |
| 10.22.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.22.3 | Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395). |
| 10.23 | Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395). |
| 10.24 | 2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.25.1 | 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395). |
| 10.25.2 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395). |
| 10.25.3 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.25.4 | Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |

| | |
|---|---|
| 10.25.6 | Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.25.7 | Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395). |
| 10.25.8 | Form of Make-Up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395). |
| 10.25.9 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.25.10 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.25.11 | Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395). |
| 10.25.12 | Form of Performance Period IX Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.25.14 | Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.25.17 | Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014 (incorporated by reference to Exhibit 10.11 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395). |
| 10.25.18 | Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.26.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395). |

| | |
|---|---|
| 10.26.1 | 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 14, 2014; File No. 001-32395). |
| 10.26.2 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 3, 2015 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2015; File No. 001-32395). |
| 10.26.3 | Form of Retention Award Terms and Conditions, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2015; File No. 001-32395). |
| 10.26.4 | Form of Non-Employee Director Restricted Stock Units Terms and Conditions, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.26.7 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.26.8 | Form of Performance Share Unit Award Terms and Conditions for Performance Period 17, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.26.9 | Form of Performance Share Unit Award Terms and Conditions for Performance Period 17 for eligible employees on the Canada payroll, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.26.10 | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395). |
| 10.26.11 | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Executive Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395). |
| 10.26.12 | Form of Key Employee Award Terms and Conditions for eligible employees on the Canada payroll, as part of the ConocoPhillips Executive Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395). |

| | |
|---|---|
| 10.26.13 | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395). |
| 10.26.14 | Form of Retention Award Terms and Conditions, 2017 revision, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27.15 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395). |
| 10.26.15 | Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2019. |
| 10.27 | Amended and Restated 409A Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated January 1, 2020 (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |
| 10.28 | Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.29 | Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395). |
| 10.30 | Amendment and Restatement of Deferred Compensation Trust Agreement for Non-Employee Directors of Phillips Petroleum Company, dated June 23, 1995 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395). |
| 10.30.1 | Successor Trustee Agreement of the Deferred Compensation Trust Agreement for Non-Employee Directors of ConocoPhillips dated July 31, 2020 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2020; File No. 001-32395). |
| 10.30.2 | First Amendment to the Successor Trust Agreement of the Deferred Compensation Trust Agreement for Non-Employee Directors of ConocoPhillips, dated August 4, 2020 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2020; File No. 001-32395). |
| 10.31 | Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.32 | Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |

| | |
|---|---|
| 10.33 | Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.34 | Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.35 | Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395). |
| 10.36 | ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395). |
| 10.37 | Term Loan Agreement, between ConocoPhillips, as borrower, ConocoPhillips Company, as guarantor, Toronto Dominion (Texas) LLC, as administrative agent and the banks party thereto, with TD Securities (USA) LLC, as lead arranger and bookrunner, dated March 18, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on March 21, 2016; File No. 001-32395). |
| 10.38 | Company Retirement Contribution Make-Up Plan of ConocoPhillips, dated December 28, 2018 (incorporated by reference to Exhibit 10.39 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395). |
| 10.40 | Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 23, 2019 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2019; File No. 001-32395). |
| 10.41 | ConocoPhillips Executive Restricted Stock Unit Program, dated February 11, 2020 (incorporated by reference to Exhibit 10.1 to the Quarter Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2020; File No. 001-32395). |
| 10.42 | Letter agreement with Don E. Wallette, Jr. dated August 3, 2020 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2020; File No. 001-32395). |
| 21* | List of Subsidiaries of ConocoPhillips. |
| 22* | Subsidiary Guarantors of Guaranteed Securities |
| 23.1* | Consent of Ernst & Young LLP. |
| 23.2* | Consent of DeGolyer and MacNaughton. |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |

| | |
|---|---|
| 32* | Certifications pursuant to 18 U.S.C. Section 1350. |
| 99* | Report of DeGolyer and MacNaughton. |
| 101.INS* | Inline XBRL Instance Document. |
| 101.SCH* | Inline XBRL Schema Document. |
| 101.CAL* | Inline XBRL Calculation Linkbase Document. |
| 101.DEF* | Inline XBRL Definition Linkbase Document. |
| 101.LAB* | Inline XBRL Labels Linkbase Document. |
| 101.PRE* | Inline XBRL Presentation Linkbase Document. |
| 104* | Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101). |

* *Filed herewith.*

† *The schedules to this exhibit have been omitted pursuant to Item 601(b)(2) of Regulation S-K. ConocoPhillips agrees to furnish a copy of any schedule omitted from this exhibit to the SEC upon request.*

‡ *ConocoPhillips has previously been granted confidential treatment for certain portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.*

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**CONOCOPHILLIPS**

February 16, 2021

*/s/ Ryan M. Lance*
Ryan M. Lance
Chairman of the Board of Directors
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 16, 2021, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

| Signature | Title |
|---|---|
| */s/ Ryan M. Lance*<br>Ryan M. Lance | Chairman of the Board of Directors<br>and Chief Executive Officer<br>(Principal executive officer) |
| */s/ William L. Bullock, Jr.*<br>William L. Bullock, Jr. | Executive Vice President and<br>Chief Financial Officer<br>(Principal financial officer) |
| */s/ Catherine A. Brooks*<br>Catherine A. Brooks | Vice President and Controller<br>(Principal accounting officer) |

| | |
|---|---|
| */s/ Charles E. Bunch*<br>Charles E. Bunch | Director |
| */s/ Caroline M. Devine*<br>Caroline M. Devine | Director |
| */s/ Gay Huey Evans*<br>Gay Huey Evans | Director |
| */s/ John V. Faraci*<br>John V. Faraci | Director |
| */s/ Jody Freeman*<br>Jody Freeman | Director |
| */s/ Jeffrey A. Joerres*<br>Jeffrey A. Joerres | Director |
| */s/ Timothy A. Leach*<br>Timothy A. Leach | Director |
| */s/ William H. McRaven*<br>William H. McRaven | Director |
| */s/ Sharmila Mulligan*<br>Sharmila Mulligan | Director |
| */s/ Eric D. Mullins*<br>Eric D. Mullins | Director |
| */s/ Arjun N. Murti*<br>Arjun N. Murti | Director |
| */s/ Robert A. Niblock*<br>Robert A. Niblock | Director |
| */s/ David T. Seaton*<br>David T. Seaton | Director |
| */s/ R.A. Walker*<br>R.A. Walker | Director |