CONOCOPHILLIPS
Form 10-K
February 19, 2019
Table of Contents

2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2018**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________________ to ________________

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

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

925 N. Eldridge Parkway

Houston, TX 77079

(Address of principal executive offices) (Zip Code)

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

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

Title of each class	**Name of each exchange on which registered**
Common Stock, $.01 Par Value	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

[x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

[ ] Yes [x] No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

[x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

[x] Yes [ ] No

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

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

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Emerging growth company [ ]

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

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 29, 2018, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $69.62, was $80.9 billion.

The registrant had 1,134,404,094 shares of common stock outstanding at January 31, 2019.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 14, 2019 (Part III)

Table of Contents

TABLE OF CONTENTS

PART IV

Table of Contents

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, pl predict, seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outl similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the headings Risk Factors beginning on page 20 and CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 76.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 16 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; lower-risk conventional assets in North America, Europe, Asia and Australia; liquefied natural gas (LNG) developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2018, we employed approximately 10,800 people worldwide and had total assets of $70 billion.

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

In April 2012, ConocoPhillips completed the separation of the downstream business into an independent, publicly traded energy company, Phillips 66.

SEGMENT AND GEOGRAPHIC INFORMATION

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

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2018, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, Malaysia, Libya, China and Qatar.

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

Proved worldwide crude oil, natural gas liquids, natural gas and bitumen reserves.
Net production of crude oil, natural gas liquids, natural gas and bitumen.
Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.

Table of Contents

- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

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

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2018**	2017	2016
Crude oil			
Consolidated operations	**2,533**	2,322	2,047
Equity affiliates	**78**	83	88
Total Crude Oil	**2,611**	2,405	2,135
Natural gas liquids			
Consolidated operations	**349**	354	457
Equity affiliates	**42**	45	47
Total Natural Gas Liquids	**391**	399	504
Natural gas			
Consolidated operations	**1,265**	1,267	1,807
Equity affiliates	**760**	717	730
Total Natural Gas	**2,025**	1,984	2,537
Bitumen			
Consolidated operations	**236**	250	159
Equity affiliates	**-**	-	1,089
Total Bitumen	**236**	250	1,248
Total consolidated operations	**4,383**	4,193	4,470
Total equity affiliates	**880**	845	1,954
Total company	**5,263**	5,038	6,424

Total production, including Libya, of 1,283 thousand barrels of oil equivalent per day (MBOED) decreased 7 percent in 2018 compared with 2017. The decrease in total average production primarily resulted from noncore asset dispositions, including the dispositions of our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets, and our interest in the San Juan Basin in the Lower 48 in 2017; normal field decline; and higher unplanned downtime, including a third-party pipeline outage in Malaysia in 2018. The decrease in production was partly offset by growth from the Big 3 Unconventionals Eagle Ford, Bakken and Delaware, development programs primarily in Europe and Alaska, and rampup of major projects in Asia Pacific.

Production excluding Libya was 1,242 MBOED in 2018 compared with 1,356 MBOED in 2017. The volume from closed dispositions was approximately 200 MBOED in 2017 and 15 MBOED in 2018. The volume from acquisitions was less than 10 MBOED in 2018. Our underlying production, which excludes the full-year impact of acquisitions, dispositions, and Libya, increased over 5 percent in 2018 compared with 2017.

Table of Contents

Our worldwide annual average realized price was $53.88 per BOE in 2018, an increase of 37 percent compared with $39.19 per BOE in 2017, reflecting stronger marker prices as well as a shift in our portfolio toward a higher mix of crude oil and less of bitumen and natural gas. Our worldwide annual average crude oil price increased 31 percent in 2018, from $51.96 per barrel in 2017 to $68.13 per barrel in 2018. Additionally, our worldwide annual average natural gas liquids prices increased 21 percent, from $25.22 per barrel in 2017 to $30.48 per barrel in 2018. Our worldwide annual average natural gas price increased 39 percent, from $4.07 per MCF in 2017 to $5.65 per MCF in 2018. Average annual bitumen prices decreased 2 percent, from $22.66 per barrel in 2017 to $22.29 per barrel in 2018.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids. We are the largest crude oil producer in Alaska and have major ownership interests in two of North America s largest oil fields located on Alaska s North Slope: Prudhoe Bay and Kuparuk. We also have a 100 percent interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska s largest owners of state, federal and fee exploration leases, with approximately 1.25 million net undeveloped acres at year-end 2018. Alaska operations contributed 23 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

				2018	
	Interest	Operator	Liquids MBD*	Natural Gas MMCFD**	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1%	BP	85	5	86
Greater Kuparuk Area***	91.4-94.7	ConocoPhillips	56	1	56
Western North Slope***	100.0	ConocoPhillips	44	-	44
Total Alaska			185	6	186

** Thousands of barrels per day.*

***Millions of cubic feet per day.*

**** Interest at December 31, 2018. See Acquisitions below for additional information.*

<u>*Greater Prudhoe Area*</u>

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

<u>*Greater Kuparuk Area*</u>

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

We completed a transaction in the fourth quarter of 2018 which increased our interest in the Greater Kuparuk Area by 39.2 percent. Further discussion of the transaction is included in the Acquisitions section below.

Table of Contents

Western North Slope

On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In 2015, first oil was achieved at Alpine West CD5, a drill site which extends the Alpine reservoir west into the National Petroleum Reserve-Alaska (NPR-A). In 2018, we continued drilling additional wells using the available well slots on this pad.

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

We completed a transaction in the second quarter of 2018 to increase our interest in the Western North Slope from 78 percent to 100 percent. Further discussion of the transaction is included in the Acquisitions section below.

Alaska North Slope Gas

In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation, completed preliminary front-end engineering and design (pre-FEED) technical work for a potential LNG project which would liquefy and export natural gas from Alaska s North Slope and deliver it to market. In 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment. AGDC decided to continue progressing the project on its own and signed several Memorandums of Understanding with various potential LNG buyers in Asia. AGDC has also signed a Joint Development Agreement with Sinopec, CIC Capital and Bank of China, which was recently extended to June 30, 2019. In early January 2019, recently elected Governor Dunleavy appointed new members to AGDC s board of directors who replaced AGDC s president with an interim president. The Dunleavy administration has indicated they are interested in participation in the project by ConocoPhillips, ExxonMobil and BP. We remain willing to make our equity gas available for sale to the project at mutually agreed, commercially reasonable terms.

Exploration

Appraisal of the Willow Discovery, located in the northeast portion of the National Petroleum Reserve-Alaska, continued throughout 2018 with three appraisal wells. Additionally, the West Willow-1 exploration well, drilled in 2018, resulted in an oil discovery. In 2019, we will continue appraisal of the Willow and West Willow discoveries.

The Putu 2/2A and Stony Hill 1 wells were drilled in 2018 on state and federal leases, resulting in oil discoveries. In late 2018, we commenced appraisal of the Putu Discovery with a long reach well from existing Alpine CD4 infrastructure.

The Cairn 2S-315 Well was drilled in late 2018 from the 2S drill site on state leases in the Kuparuk River Unit. A flow test will commence in the first quarter of 2019.

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

We were successful in the federal lease sale on the North Slope in the fourth quarter of 2018, where we were the high bidder on five tracts for a total of approximately 48,000 net acres.

Acquisitions

During the second quarter of 2018, we obtained regulatory approvals and completed a transaction we entered into with Anadarko Petroleum Corporation to acquire its 22 percent nonoperated interest in the Western North Slope of Alaska, as well as its interest in the Alpine Transportation Pipeline. In 2018, our Alaska segment net production included 7 MBOED associated with the additional interest acquired.

Table of Contents

During the fourth quarter of 2018, we completed a transaction with BP to acquire their 39.2 percent nonoperated interest in the Greater Kuparuk Area, including their 38 percent interest in the Kuparuk Transportation Company in Alaska (Kuparuk Assets), and to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. In 2018, our Alaska segment net production included 1 MBOED associated with the additional interest acquired in the Greater Kuparuk Area.

See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Transportation

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

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

LOWER 48

The Lower 48 segment consists of operations located in the contiguous United States and the Gulf of Mexico. The Lower 48 business is organized within two regions covering the Gulf Coast and Great Plains. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost of supply plays. We disposed of several noncore assets within the Lower 48 in 2018, including our interests in the Barnett and certain conventional assets in the Permian Basin. In 2017, we disposed of our interest in the San Juan Basin. We hold 10.3 million net onshore and offshore acres in the Lower 48. In 2018, the Lower 48 contributed 36 percent of our worldwide liquids production and 21 percent of our natural gas production.

				2018	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various%	Various	151	212	186
Gulf of Mexico	Various	Various	12	9	14
Gulf Coast Other	Various	Various	3	8	4
Total Gulf Coast			166	229	204
Bakken	Various	Various	72	72	84
Permian	Various	Various	46	126	66
Anadarko Basin	Various	Various	4	59	14
Wyoming/Uinta	Various	Various	-	78	13
Barnett	*	Various	3	25	8

Niobrara	Various	Various	7	7	8
Total Great Plains			132	367	193
Total U.S. Lower 48			298	596	397

**See Dispositions below for additional information.*

Table of Contents

Onshore

We hold 10.3 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 1.6 million net acres in the following areas:

- 620,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 225,000 net acres in central Louisiana.
- 200,000 net acres in the Eagle Ford, located in South Texas.
- 145,000 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 98,000 net acres in the Niobrara, located in northeastern Colorado.
- 340,000 net acres in other areas with unconventional potential.

The majority of our 2018 onshore production originated from the Big 3 Eagle Ford, Bakken and the Delaware in the Permian Basin. Onshore activities in 2018 were centered mostly on continued development of assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. Our major focus areas in 2018 included the following:

- Eagle Ford The Eagle Ford continued full-field development in 2018. We operated seven rigs on average in 2018, resulting in 166 operated wells drilled and 149 operated wells brought online. Production increased 40 percent in 2018 compared with 2017, averaging 186 MBOED and 133 MBOED, respectively.
- Bakken We operated an average of three rigs during the year in the Bakken. We continued our pad drilling with 51 operated wells drilled during the year and 85 operated wells brought online. Production increased 29 percent in 2018 compared with 2017, averaging 84 MBOED and 65 MBOED, respectively.
- Permian Basin The Permian Basin is an area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. We hold approximately 800,000 net acres in the Permian, which includes 145,000 net unconventional acres. The Permian Basin produced 66 MBOED in 2018, increasing 6 percent compared to 2017, including 28 MBOED of unconventional production from the Delaware. We disposed of several noncore conventional assets throughout the year.

Dispositions

We completed the sale of our interests in the Barnett in the fourth quarter of 2018. Combined with the sale of several noncore conventional assets in the Permian Basin, production from the assets sold was 10 MBOED, approximately 3 percent of total Lower 48 production in 2018. For additional information on our asset dispositions, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Gulf of Mexico

At year-end 2018, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, totaling approximately 68,000 net acres, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.

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

Table of Contents

Exploration

Conventional Exploration

In December 2017, we elected to withdraw from our Shenandoah leases. The withdrawal was effective February 17, 2018, substantially completing our exit from deepwater Gulf of Mexico.

Unconventional Exploration

Our onshore focus areas include the Niobrara in the Denver-Julesburg Basin, the Delaware in the Permian Basin, as well as several emerging plays such as the Louisiana Austin Chalk. We began acquiring early life-cycle acreage in the Austin Chalk in the fourth quarter of 2017, and currently hold approximately 225,000 net acres. We spud our first Austin Chalk well in late 2018 and plan to drill additional wells in 2019.

Facilities

Golden Pass LNG Terminal

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $235 million at December 31, 2018. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. In January 2019, we entered into agreements to sell our 12.4 percent ownership interest in Golden Pass LNG Terminal and the affiliated Golden Pass Pipeline. We have also entered into agreements to amend our contractual obligations for remaining use of the facilities. Completion of the sale is subject to regulatory approval.

Other

- Lost Cabin Gas Plant We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 246 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming. The Plant is currently operating at less than capacity due to a fire in December 2018. Restoration efforts are ongoing and anticipated to continue throughout 2019. The expected production loss in 2019 is approximately 7 MBOED.
- Helena Condensate Processing Facility We operate and own the Helena Condensate Processing Facility, a 110,000 barrel-per-day condensate processing plant located in Kenedy, Texas.
- Sugarloaf Condensate Processing Facility We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

Table of Contents

CANADA

Our Canadian operations mainly consist of an oil sands development in the Athabasca Region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2018, operations in Canada contributed 8 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

			2018			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Surmont	50.0%	ConocoPhillips	-	-	66	66
Montney	100.0	ConocoPhillips	2	12	-	4
Total Canada			2	12	66	70

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Production from the assets sold was 103 MBOED, approximately 62 percent of the total Canada segment production in 2017. For additional information on our asset dispositions, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Oil Sands

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

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

Exploration

We hold exploration acreage in three areas of Canada: onshore western Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada.

We hold approximately 145,000 net acres in the emerging unconventional Montney play in northeast British Columbia and 207,000 net acres in Canol Northwest Territories. Our Montney activity in 2018 included drilling 13 horizontal wells, completing two horizontal wells and acquiring approximately 37,000 additional net acres. Appraisal drilling and completions activity will continue in 2019 to further explore the area s resource potential.

Table of Contents

EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2018, operations in Europe and North Africa contributed 19 percent of our worldwide liquids production and 18 percent of natural gas production.

Norway

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1%	ConocoPhillips	53	45	60
Heidrun	24.0	Equinor	12	25	16
Alvheim	20.0	Aker BP	11	11	13
Visund	9.1	Equinor	5	44	12
Troll	1.6	Equinor	2	60	12
Other	Various	Equinor	8	9	10
Total Norway			91	194	123

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises three producing fields: Ekofisk, Eldfisk and Embla. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. The Ekofisk and Eldfisk fields consist of several production platforms and facilities, including the Ekofisk South and Eldfisk II developments which achieved first production in 2013 and 2015, respectively. Continued development drilling in the Greater Ekofisk Area will contribute additional production over the coming years, as additional wells come online.

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

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

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

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

We also have varying ownership interests in two other producing fields in the Norway sector of the North Sea, as well as the Aasta Hansteen development in the Norwegian Sea, which achieved first production in December 2018.

Table of Contents

Exploration

In 2018, we participated in the Gekko appraisal well and sidetrack in the Alvheim Area of the North Sea and encountered hydrocarbons. The Gekko Discovery is currently under evaluation as a future tie-in to the Alvheim Facility. In 2018, we were awarded six new exploration licenses; PL911, PL912, PL917, PL919, PL935 and PL938; and one acreage addition, PL775B.

Transportation

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

United Kingdom

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Britannia	58.7%	ConocoPhillips	3	74	15
Britannia Satellites	26.3 93.8*	ConocoPhillips	12	92	27
J-Area	32.5 36.5	ConocoPhillips	9	57	19
Clair	7.5**	BP	6	1	6
East Irish Sea	100.0	Spirit Energy	-	30	5
Southern North Sea	Various	ConocoPhillips	-	22	4
Other	Various	Various	-	5	1
Total United Kingdom			30	281	77

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

***See dispositions below for additional information.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia s line to St. Fergus, Scotland. The Britannia satellite fields, Callanish, Brodgar, Enochdhu and Alder, produce via subsea manifolds and pipelines linked to the Britannia Platform.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The J-Area gas is processed on the Judy Platform and transported through the Central Area Transmission System Pipeline, while liquids are transported to Teesside through the Norpipe system. Continued development drilling in the J-Area will provide additional volumes in the coming years as wells are brought online.

We have various ownership interests in several gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Production ceased in August 2018, and decommissioning activity in the Southern North Sea is ongoing.

Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 7.5 percent interest in the Clair Field, located in the Atlantic Margin. We completed the sale of a subsidiary holding a 16.5 percent interest in the Clair Field in December 2018 to BP. See the Disposition section below for more information. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities tie into existing oil and gas export pipelines to the Shetland Islands. First production for Clair Ridge was achieved in November 2018.

Table of Contents

Exploration

In 2018, we drilled the Jasmine 2A exploration well. The well encountered insufficient hydrocarbons and was expensed as a dry hole. In 2018, we were awarded two new exploration licenses in the J-Area, P2399 and P2456.

Transportation

We operate the Teesside oil and Theddlethorpe gas terminals in which we have 40.25 percent and 50 percent ownership interests, respectively. Decommissioning activity is ongoing at the Theddlethorpe gas terminal following cessation of production in the Southern North Sea. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

Disposition

In the fourth quarter of 2018, we completed a transaction to sell a ConocoPhillips subsidiary, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom to BP, and acquire their nonoperated interest in the Kuparuk Assets in Alaska. In 2018, our Europe and North Africa segment net production associated with the disposed 16.5 percent interest in the Clair Field was approximately 5 MBOED. See Note 5   Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Libya

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3%	Waha Oil Co.	36	28	41
Total Libya			36	28	41

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports have periodically been interrupted over the last several years due to the shutdown of the Es Sider crude oil export terminal. In 2018, we had 21 crude liftings from Es Sider. We expect a gradual, continued rampup in activity.

Table of Contents

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia and producing operations in Qatar and Timor-Leste. In 2018, operations in the Asia Pacific and Middle East segment contributed 14 percent of our worldwide liquids production and 60 percent of natural gas production.

Australia and Timor Sea

				2018	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	660	110
Bayu-Undan	56.9	ConocoPhillips	7	240	47
Athena/Perseus	50.0	ExxonMobil	-	35	6
Total Australia and Timor Sea			7	935	163

Australia Pacific LNG

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

Two fully subscribed 4.5-million-metric-tonnes-per-year LNG trains have been completed. Approximately 3,900 net wells are ultimately expected to supply both the domestic gas market and the LNG sales contracts. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities, and an export pipeline connecting the gas fields to the LNG facilities. The first APLNG Train 1 cargo sailed in January 2016, and APLNG Train 2 achieved first production in the third quarter of 2016. The LNG is being sold to Sinopec under 20-year sales agreements for 7.6 million metric tonnes of LNG per year, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

APLNG has an $8.5 billion project finance facility, which was fully drawn down and had an outstanding balance of $7.2 billion at December 31, 2018. In September 2018, APLNG successfully refinanced $1.4 billion of the project finance facility for a lower cost United States Private Placement (USPP) bond facility. Project finance interest payments are bi-annual, concluding September 2030.

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

Bayu-Undan

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

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 310-mile natural gas pipeline connects the facility to the 3.5-million-metric-tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2018, we sold 157 billion gross cubic feet of LNG primarily to utility customers in Japan.

Table of Contents

A continuation of the Bayu-Undan Phase Three Development consisting of one subsea and two platform wells was completed with all three wells producing by November 2018.

Athena/Perseus

The Athena production license (WA-17-L) in which ConocoPhillips has a 50 percent working interest is located offshore Western Australia and contains part of the Perseus Field which straddles the boundary with WA-1-L, an adjoining license area. The production entitlement to natural gas produced from WA-17-L is forecast to end in the fourth quarter of 2019.

Greater Sunrise

In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals.

Exploration

We operate three exploration permits in the Browse Basin, offshore northwest Australia, in which we own a 40 percent interest in permits WA-315-P, WA-398-P and TP 28, of the Greater Poseidon Area. The TP 28 Western Australia State exploration permit was granted for five years from January 2017, with a 40 percent working interest and was excised from the existing permits as agreed between state and federal regulators. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. All wells have been plugged and abandoned.

We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. A 3-D seismic survey was completed over the Barossa and Caldita fields in 2016. The drilling of the Barossa-5A and Barossa-6 appraisal wells was completed in 2017 with good quality, gas-bearing reservoir intersected at both. Additionally, the retention lease over the Barossa Field was renewed during 2017. In April 2018, Barossa entered the front-end engineering and design (FEED) phase of development which will continue through 2019. During the FEED phase, costs and the technical definition for the project will be finalized, gas and condensate sales agreements progressed, and access arrangements negotiated with the owners of the Darwin LNG Facility and Bayu-Darwin Pipeline.

Indonesia

				2018	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Sumatra	45.0 54.0%	ConocoPhillips	2	309	53

Total Indonesia	2	309	53

We operate three production sharing contracts (PSC) in Indonesia: The Corridor Block and South Jambi B, both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently, there is production from the Corridor Block.

Table of Contents

South Sumatra

The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. Production from the South Jambi B PSC has reached depletion and field development has been suspended. This PSC will expire in January 2020.

Exploration

We have a 60 percent working interest in the Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 1.4 million gross acres. Technical evaluation is on-going to determine the block s potential.

Transportation

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

China

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Penglai	49.0%	CNOOC	30	-	30
Panyu	24.5	CNOOC	6	-	6
Total China			36	-	36

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2, which included six additional wellhead platforms and an FPSO vessel, was fully operational by 2009.

As part of further development of the Penglai 19-9 Field, the new wellhead platform J Project, which anticipates 62 wells, is progressing according to schedule, with 36 wells completed and brought online through December 2018.

The Penglai 19-3/19-9 Phase 3 Project was sanctioned in December 2015. This project consists of three new wellhead platforms and a central processing platform. First oil from Phase 3 was achieved in 2018.

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

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The production period for Panyu 4-2, 5-1 and 11-6 will expire in 2019.

Exploration

In 2018, we participated in one successful appraisal well in the Bohai Penglai Field. We continued the Penglai full-field 3-D seismic program, covering existing and future development opportunities. The program is expected to complete in 2019.

Table of Contents

Malaysia

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Siakap North-Petai	21.0%	Murphy	2	1	2
Gumusut	29.0	Shell	25	-	25
KBB	30.0	KPOC	1	41	8
Malikai	35.0	Shell	19	-	19
Total Malaysia			47	42	54

We own interests in six PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, Block SK304, Block SK313 and Block WL4-00 are located off the eastern Malaysian state of Sarawak.

Block G

We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014.

We own a 35 percent interest in Malikai. The field achieved first production in December 2016, ramping to peak production in 2018. The KMU-1 exploration well was completed and started producing in 2018.

Block J

First production from the Gumusut Field occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014. Our ownership in the Gumusut Field is currently at 29 percent following the finalization of the Malaysia-Brunei unitization and a redetermination of the Block J and Block K Malaysia Unit, both in 2017. The drilling of the Gemilang-1 exploration well in Block J is complete and the results are under review. Gumusut Phase 2 infill drilling and first oil from Phase 2 are expected in 2019.

KBBC

We have a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Production in 2018 was impacted by unplanned downtime related to the rupture of a third-party pipeline which carries gas production from the Kebabangan gas field to market. Development options for the Kamunsu East gas field are being evaluated.

Exploration

In the fourth quarter of 2016, we entered into a farm-in agreement to acquire a 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block, effective January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS.

We were awarded Block WL4-00, which encompasses 0.6 million gross acres, in January 2017. We have a 50 percent operated interest in this block which includes the Salam-1 oil discovery.

We completed a 3-D seismic survey in Block SK 313 and Block WL4-00 in 2017. Two wells were drilled in Block WL4-00 in 2018 and discovered hydrocarbons. Further exploration drilling is expected to occur in 2019.

We were awarded Block SK304 in May 2018, which encompasses 2.1 million gross acres. We completed a 3-D seismic survey in this block in 2018.

Table of Contents

Brunei

Exploration

In October 2018, we assigned our 6.25 percent working interest in the deepwater Block CA-2 PSC to Brunei National Petroleum Company Sendirian Berhad.

Qatar

			2018		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
QG3	30.0%	Qatargas Operating Company Limited	21	371	83
Total Qatar			21	371	83

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

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

OTHER INTERNATIONAL

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

Colombia

Exploration

We have an 80 percent operated interest in the Middle Magdalena Basin Block VMM-3. The block extends over approximately 67,000 net acres and contains the Picoplata-1 Well, which completed drilling in 2015 and testing in 2017. Plug and abandonment activity started during 2018 and is expected to continue into 2019. In addition, we have an 80 percent working interest in the VMM-2 Block which extends over approximately 58,000 net acres and is contiguous to the VMM-3 Block. Community engagement and environmental permitting activities are expected to continue in 2019.

Chile

Exploration

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

Argentina

Exploration

We received government approval in January 2019 for a 50 percent nonoperated interest in the El Turbio Este Block in the Austral Basin.

Venezuela and Ecuador

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

OTHER

Marketing Activities

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

Natural Gas

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

Crude Oil, Bitumen and Natural Gas Liquids

Our crude oil, bitumen and natural gas liquids revenues are derived from production in the United States, Canada, Australia, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

LNG

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

Energy Partnerships

Marine Well Containment Company (MWCC)

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

Subsea Well Response Project (SWRP)

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

Oil Spill Response Removal Organizations (OSROs)

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

Table of Contents

Technology

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

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

RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2018. No difference exists between our estimated total proved reserves for year-end 2017 and year-end 2016, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2018.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 1.5 trillion cubic feet of natural gas, including approximately 243 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 73 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2029. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill any remaining commitments. See the disclosure on Proved Undeveloped Reserves in the Oil and Gas Operations section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

COMPETITION

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

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 3, 2018, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide natural gas and liquids production and worldwide liquids reserves in 2017. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

Table of Contents

GENERAL

At the end of 2018, we held a total of 814 active patents in 50 countries worldwide, including 333 active U.S. patents. During 2018, we received 29 patents in the United States and 67 foreign patents. Our products and processes generated licensing revenues of $53 million related to activity in 2018. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Health, Safety and Environment

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

The environmental information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 65 through 69 under the captions Environmental and Climate Change is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2018 and those expected for 2019 and 2020.

Website Access to SEC Reports

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

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

Table of Contents

Item 1A. RISK FACTORS

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

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

Prices for crude oil, bitumen, natural gas, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have experienced significant declines from their historic levels during 2013 and 2014, with excess of supply relative to global demand leading to global inventory builds. Although commodity prices began to rise in 2018, there was a sharp drop in crude oil prices in the fourth quarter of 2018, ending 2018 lower than where they started at the beginning of the year for the first time since 2015. Given volatility in commodity price drivers and the worldwide economic environment generally, price trends may continue to be volatile.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, natural gas liquids and LNG. The factors influencing these prices are beyond our control.

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

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

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

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

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

Our operating expenses.
Other factors our Board of Directors deems relevant.

Table of Contents

We expect to continue to pay quarterly distributions to our stockholders; however, our Board of Directors may determine that our funds generated by operations, after deducting operating expenses, are not sufficient to pay our desired levels of distributions to our stockholders or to pay distributions to our stockholders at all.

Additionally, our Board of Directors has authorized a $15 billion share repurchase program, of which $9 billion of repurchase authority remained as of December 31, 2018. Our share repurchase program does not obligate us to acquire a specific number of shares during any period, and our decision to commence, discontinue or resume repurchases in any period will depend on the same factors that our Board of Directors may consider when declaring distributions, among others.

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

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

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

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. For example, due to the significant decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG in 2015, and the expectation that these prices could remain depressed, the major ratings agencies conducted a review of the oil and gas industry and downgraded our debt ratings and those of several companies operating in the industry in 2016. Any downgrade in our credit rating or announcement that our credit rating is under review for possible downgrade could increase the cost associated with any additional indebtedness we incur.

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

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

In particular, in August 2018, we entered into a settlement agreement with Petróleos de Venezuela, S.A. (PDVSA) providing for the payment of approximately $2 billion over a five-year period in connection with an arbitration award issued by the International Chamber of Commerce (ICC) Tribunal in favor of ConocoPhillips on a contractual dispute arising from Venezuela s expropriation of our interests in the Petrozuata and Hamaca heavy oil ventures and other pre-expropriation fiscal measures. We collected approximately $0.4 billion of the $2 billion settlement in 2018. If PDVSA were to default on any of its remaining payment obligations under this agreement, we may be forced to incur additional costs as we seek to recover any unpaid amounts under the agreement.

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

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil, bitumen, natural gas and natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, our business will experience reduced cash flows and results of operations. Any cash conservation efforts we may undertake as a result of commodity price declines may further limit our ability to replace depleted reserves.

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

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

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

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

One area subject to significant political and regulatory activity is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal and national laws and regulations currently govern or, in some hydraulic fracturing operations, prohibit hydraulic fracturing in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA) and others which could result in increased costs, operating restrictions, operational delays or limit the ability to develop oil and natural gas resources. Certain jurisdictions in which we operate, including state and local governments in Colorado, have adopted or are considering regulations that could impose new or more stringent permitting, disclosure or other regulatory requirements on hydraulic fracturing or other oil and natural-gas operations, including subsurface water disposal. In addition, certain interest groups have also proposed ballot initiatives and constitutional amendments designed to restrict oil and natural-gas development generally and hydraulic fracturing in particular. For example, in 2018, Colorado voters rejected Proposition 112, a Colorado ballot initiative that would have drastically limited the use of hydraulic fracturing in Colorado. In the event that ballot initiatives, local or state restrictions or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development or production activities. Such compliance costs and delays, curtailments, limitations or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition and liquidity.

Table of Contents

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

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 55 percent of our hydrocarbon production was derived from production outside the United States in 2018, and 41 percent of our proved reserves, as of December 31, 2018, were located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids or LNG pricing and taxation, other political, economic or diplomatic developments (including the effect of international trade discussion and disputes), changing political conditions and international monetary and currency rate fluctuations. In particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

Table of Contents

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2018, as well as matters previously reported in our 2017 Form 10-K and our first-, second- and third-quarter 2018 Form 10-Qs that were not resolved prior to the fourth quarter of 2018. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

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

Matters Previously Reported Phillips 66

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

Matters Previously Reported ConocoPhillips

On June 28, 2018, the Texas Commission on Environmental Quality issued a Proposed Agreed Order to ConocoPhillips Company to resolve alleged violations of the Texas Health & Safety Code and/or Commission Rules occurring in 2015 through 2017 at a formerly owned gas injection plant in Howard County, Texas, through the payment of a penalty of $457,750 and the implementation of measures designed to prevent a reoccurrence. The company will work with the Commission to promptly resolve this matter.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Catherine A. Brooks	Vice President and Controller	53
William L. Bullock, Jr.	President, Asia Pacific & Middle East	54
Ellen R. DeSanctis	Senior Vice President, Corporate Relations	62
Matt J. Fox	Executive Vice President and Chief Operating Officer	58
Michael D. Hatfield	President, Alaska, Canada and Europe	52
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	56
Andrew D. Lundquist	Senior Vice President, Government Affairs	58
Dominic E. Macklon	President, Lower 48	49
Kelly B. Rose	Senior Vice President, Legal, General Counsel and Corporate Secretary	52
Don E. Wallette, Jr.	Executive Vice President and Chief Financial Officer	60

**On February 15, 2019.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 14, 2019. Set forth below is information about the executive officers.

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

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

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

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

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

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

Table of Contents

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

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

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

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

Table of Contents

PART II

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

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

Cash Dividends Per Share

		Dividends	
		2018	2017
First	$	**0.285**	0.265
Second		**0.285**	0.265
Third		**0.285**	0.265
Fourth		**0.305**	0.265

Number of Stockholders of Record at January 31, 2019*	44,084

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

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

On January 31, 2017, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.265 per share, compared with the previous quarterly dividend of $0.25 per share.

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

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

Table of Contents

Issuer Purchases of Equity Securities

				Millions of Dollars
Period	Total Number of Shares Purchased*	Average Price Paid Per Share	Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2018	4,155,118	$ 74.45	4,155,118	$ 9,492
November 1-30, 2018	4,642,077	66.57	4,642,077	9,183
December 1-31, 2018	4,808,691	63.87	4,808,691	8,875
Total fourth-quarter 2018	13,605,886	$ 68.02	13,605,886	$ 8,875

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

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock through 2019, with $3 billion allocated and purchased in 2017, and the remainder allocated evenly to 2018 and 2019. On February 1, 2018, we announced the acceleration of our previously stated 2018 share repurchases from $1.5 billion to $2 billion. On July 12, 2018, we announced plans to further accelerate our 2018 share repurchases to $3 billion. The 2018 expansion to $3 billion, combined with the $3 billion of shares repurchased during 2016 and 2017, fully utilized the Board of Directors existing share repurchase authorization of $6 billion. As a result, our Board authorized an additional $9 billion for share repurchases, at any time or from time to time (whether before, on or after December 31, 2019), bringing the total program authorization to $15 billion. Acquisitions for the share repurchase program are made at management s discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares. See Risk Factors Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Stock Performance Graph

The following graph shows the cumulative total shareholder return (TSR) for ConocoPhillips common stock in each of the five years from December 31, 2013, to December 31, 2018. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index and our performance peer group consisting of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Anadarko, Apache, Marathon Oil Corporation, Devon and Occidental, weighted according to the respective peer s stock market capitalization at the beginning of each annual period. The comparison assumes $100 was invested on December 31, 2013, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips peer group and assumes that all dividends were reinvested.

Table of Contents

Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2018	2017	2016	2015	2014
Sales and other operating revenues	**$ 36,417**	29,106	23,693	29,564	52,524
Income (loss) from continuing operations	**6,305**	(793)	(3,559)	(4,371)	5,807
Per common share					
Basic	**5.36**	(0.70)	(2.91)	(3.58)	4.63
Diluted	**5.32**	(0.70)	(2.91)	(3.58)	4.60
Income from discontinued operations	**-**	-	-	-	1,131
Net income (loss)	**6,305**	(793)	(3,559)	(4,371)	6,938
Net income (loss) attributable to ConocoPhillips	**6,257**	(855)	(3,615)	(4,428)	6,869
Per common share					
Basic	**5.36**	(0.70)	(2.91)	(3.58)	5.54
Diluted	**5.32**	(0.70)	(2.91)	(3.58)	5.51
Total assets	**69,980**	73,362	89,772	97,484	116,539
Long-term debt	**14,856**	17,128	26,186	23,453	22,383
Cash dividends declared per common share	**1.16**	1.06	1.00	2.94	2.84

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

Net income (loss) and net income (loss) attributable to ConocoPhillips in 2014 includes income from discontinued operations as a result of the sale of our interest in our Nigeria business.

These factors impact the comparability of historical information.

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

Table of Contents

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

Management s Discussion and Analysis is the company s analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company s plans, strategies, objectives, expectations and intentions that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential should, will, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, ta expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 76.

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

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 16 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; lower-risk conventional assets in North America, Europe, Asia and Australia; liquefied natural gas (LNG) developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2018, we employed approximately 10,800 people worldwide and had total assets of $70 billion.

Overview

In 2018, the energy industry continued to be volatile. Forecasts of worldwide economic growth and strong global demand for crude oil at the beginning of the year transitioned to concerns about a worldwide economic slowdown and an oversupply of crude oil by the end of the year. Additionally, production from major oil producing countries, including the United States, was strong. These factors caused crude oil prices to fall rapidly in the fourth quarter of 2018. Our business strategy anticipates prices will remain cyclical and is designed to be resilient in lower price environments, with significant upside during periods of higher prices.

Our value proposition principles, namely to focus on returns, maintain financial strength, grow our dividend and pursue disciplined growth, are being executed in accordance with our priorities for allocating cash flows from the business. These priorities are: invest capital at a level that maintains flat production volumes and pays our existing dividend; grow our existing dividend; maintain debt at a level we believe is sufficient to maintain a strong investment grade credit rating through price cycles; repurchase shares to provide value to our shareholders; and invest capital to grow our cash from operations.

In 2018, we successfully delivered on our priorities. We increased our quarterly dividend by 15 percent to $0.305 per share; reduced our debt by $4.7 billion, achieving our debt reduction target 18 months ahead of plan and received credit rating upgrades from Fitch, Moody s and Standard & Poor s; repurchased 45 million shares of our common stock totaling $3.0 billion and received Board authorization for an incremental $9 billion of share repurchases; and added to our low cost of supply resource base, including increasing our legacy asset position in Alaska through two separate acquisitions.

Portfolio optimization, debt reduction and disciplined capital investment have positioned our company to navigate through periods of volatile energy prices. In December 2018, we announced our 2019 capital budget of $6.1 billion, which is less than our 2018 capital expenditures and investments of $6.8 billion. Our 2019 capital budget is relatively flat to the prior year when excluding $0.6 billion of acquisitions made in 2018. At this level of capital, production excluding Libya is expected to be 1,300 to 1,350 thousand barrels of oil equivalent per day (MBOED) in 2019 and would exceed 2018 production excluding Libya of 1,242 MBOED. This plan anticipates cash provided by operating activities in excess of capital expenditures and investments at prices above $40 per barrel West Texas Intermediate (WTI).

Key Operating and Financial Summary

Significant items during 2018 included the following:

- Cash provided by operating activities was $12.9 billion and exceeded capital expenditures and investments of $6.8 billion, share repurchases of $3 billion and dividends of $1.4 billion.
- The $4.4 billion of share repurchases and dividends represents 34 percent of cash provided by operating activities.
- Reduced debt by $4.7 billion and achieved $15 billion debt target 18 months ahead of plan.
- Received credit rating upgrades from Fitch, Moody s and Standard & Poor s.
- Full-year production excluding Libya of 1,242 MBOED; underlying production grew 18 percent on a production per debt-adjusted share basis.
- Increased full-year Lower 48 Big 3 production Eagle Ford, Bakken and Delaware by 37 percent.
- Achieved first production from Bayu-Undan final development phase, GMT-1, Bohai Phase 3, Aasta Hansteen and Clair Ridge.
- Acquired additional working interest in our legacy assets in Alaska and increased our acreage in the liquids-rich Montney play in Canada and in the early-life cycle unconventional Louisiana Austin Chalk.
- Executed successful exploration program in Alaska and started drilling in Louisiana Austin Chalk.
- Reached a settlement agreement with Petroleos de Venezuela, S.A. (PDVSA) to fully recover the International Chamber of Commerce (ICC) arbitration award of approximately $2 billion; recognized $430 million before-tax toward the settlement.
- Generated disposition proceeds of $1.1 billion from noncore asset sales.
- Year-end proved reserves of 5.3 billion barrels of oil equivalent (BOE); 147 percent total reserve replacement and 109 percent organic replacement ratio.

Operationally, we continue to focus on safely executing our capital program and remaining diligent on our costs. Production, including Libya, of 1,283 MBOED decreased 7 percent in 2018 compared with 2017. The volume from closed dispositions was approximately 200 MBOED in 2017 and 15 MBOED in 2018. The volume from acquisitions was less than 10 MBOED in 2018. Production from Libya was 21 MBOED in 2017 and 41 MBOED in 2018. Our underlying production, which excludes the full-year impact of acquisitions, dispositions, and Libya, increased over 5 percent in 2018 compared with 2017. Underlying production on a per debt-adjusted share basis grew by 18 percent compared to 2017. Production per debt-adjusted share is calculated on an underlying production basis using ending period debt divided by ending share price plus ending shares outstanding. We believe production per debt-adjusted share is useful to investors as it provides a consistent view of production on a total equity basis by converting debt to equity and allows for comparison across peer companies.

In the second quarter of 2018, we obtained regulatory approvals and completed a transaction with Anadarko Petroleum Corporation to acquire its 22 percent nonoperated interest in the Western North Slope of Alaska, as well as its interest in the Alpine Transportation Pipeline, for $386 million, after customary adjustments. In 2018, our Alaska segment net production included 7 MBOED associated with the additional interest acquired. In addition, we now have 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery.

In the fourth quarter of 2018, we completed a transaction with BP to acquire its nonoperated interest in the Greater Kuparuk Area and Kuparuk Transportation Company (Kuparuk Assets) in Alaska, and to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. In 2018, our Alaska segment net production included 1 MBOED associated with the additional interest acquired in the Greater Kuparuk Area, and net production in our Europe and North Africa segment included 5 MBOED related to the disposed 16.5 percent interest in the Clair Field. We recognized a $774 million after-tax gain in the fourth quarter related to this transaction. Excluding receipt of $253 million in customary adjustments, this transaction was cash neutral.

In the fourth quarter of 2018, we completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments. In 2018, our Lower 48 segment net production included 8 MBOED related to the disposed interest in the Barnett, of which approximately 55 percent was natural gas and 45 percent was natural gas liquids. After-tax impairment charges of $69 million were recognized during 2018.

In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals. No production or reserve impacts are associated with the sale. Proceeds from this transaction will be used for general corporate purposes. The Greater Sunrise Fields are included in our Asia Pacific and Middle East segment.

For more information regarding the accounting impacts of these transactions, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Also during 2018, we entered into a settlement agreement with PDVSA to recover approximately $2 billion, which reflects the full amount awarded to ConocoPhillips by an arbitral tribunal constituted under the rules of the ICC. PDVSA has agreed to recognize the ICC judgment and to make payments over the next four and a half years. During the year, we recognized in other income $417 million after-tax, consisting of $200 million in cash and the remainder in commodity inventory, the majority of which was sold by year end. For more information, see Note 4 Inventories and Note 13 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Business Environment

Brent crude oil prices averaged over $60 per barrel in the first quarter of 2018, rising to over $70 per barrel in the second and third quarters of 2018, before falling to the $50 per barrel range at the end of the year. The energy industry has periodically experienced this type of volatility due to fluctuating supply-and-demand conditions. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Our strategy is to create value through price cycles by delivering on the disciplined financial and operational priorities that underpin our value proposition.

Operational and Financial Factors Affecting Profitability

The focus areas we believe will drive our success through the price cycles include:

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

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

- Control costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment. The ability to control our operating and overhead costs impacts our ability to deliver strong cash from operations. In 2018, our production and operating expenses were relatively flat to 2017.

- Maintain capital discipline. We participate in a commodity price-driven and capital intensive industry, with varying lead times from when an investment decision is made to the time an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and LNG facilities. We allocate capital across diverse, low cost of supply, programs in our resource base. Our cash allocation priorities call for the investment of sufficient capital to maintain production and pay the existing dividend. Additional allocations of capital toward growth projects will be dependent on satisfaction of other financial priorities. In setting our capital plans, we exercise a disciplined approach that evaluates projects on a cost of supply basis and is focused on value maximization and cash flow expansion.

In December 2018, we announced a 2019 capital budget of $6.1 billion, including $3.8 billion of sustaining capital to maintain existing production levels, and $2.3 billion to grow production via short-cycle unconventional programs, future major projects and exploration activities.

- Optimize our portfolio. We continue to optimize our asset portfolio by focusing on low cost of supply assets that support our strategy. In 2018, we continued to dispose of or market certain noncore assets and made two acquisitions in Alaska to enhance our existing legacy asset position. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

Maintain financial strength. We believe financial strength is critical in a cyclical business such as ours. In 2018, we reduced our debt by $4.7 billion to $15.0 billion at year end, achieving our debt reduction target 18 months ahead of plan and received credit rating upgrades from Fitch, Moody s and Standard & Poor s. We expect to retire outstanding debt as it matures and exercise flexibility in paying down our other debt instruments.

Return capital to shareholders. In 2018, we paid dividends on our common stock of approximately $1.4 billion and repurchased $3 billion of our common stock, representing 34 percent of our cash provided by operating activities. We believe in delivering value to our shareholders through the price cycles. As a result, we set a priority to increase our dividend rate annually and consistently repurchase shares on a dollar cost average basis. Since we initiated our current share repurchase program in late

2016, we have bought back $6 billion of shares, with $9 billion remaining on our existing authorization. Our 2018 dividends, share repurchases, and capital program were fully funded with cash provided by operating activities.

On February 1, 2018, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share. In October 2018, we announced a dividend increase for the second time this year, an additional 7 percent, resulting in a quarterly dividend rate of $0.305 per share.

In addition to the $6 billion of shares repurchased in 2016 through the end of 2018, in July 2018 we announced the authorization of an additional $9 billion share repurchases. We expect to execute $3 billion of this $9 billion share repurchase program in 2019. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including market conditions and other factors. See Risk Factors Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

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

- Successful exploration, exploitation and development of new and existing fields.
- Application of new technologies and processes to improve recovery from existing fields.

Proved reserve estimates require economic production based on historical 12-month, first-of-month, average prices and current costs. Therefore, our proved reserves generally increase as prices rise and decrease as prices decline. Reserve replacement represents the net change in proved reserves, net of production, divided by our current year production, as shown in our supplemental reserve table disclosures. In 2018, our reserve replacement, which included a net increase of 0.2 billion BOE from sales and purchases, was 147 percent. Increased crude oil reserves accounted for over 90 percent of the total change in reserves. Our organic reserve replacement, which excludes the impact of sales and purchases, was 109 percent in 2018. Approximately 33 percent of organic reserve additions are from Lower 48 unconventional assets, 29 percent from Alaska and 22 percent from Asia Pacific and Middle East.

In the five years ended December 31, 2018, our reserve replacement was negative 30 percent, reflecting the impact of asset dispositions and lower prices during that period. Our organic reserve replacement during the five years ended December 31, 2018, which excludes a decrease of 2.1 billion MMBOE related to sales and purchases, was 44 percent, reflecting development activities as well as lower prices during that period.

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

Apply technical capability. We leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage, and we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations. Such innovations enhance our ability to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

Develop and retain a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills and experience. We promote continued learning, development and technical training through structured development programs designed to enhance the technical and functional skills of our employees.

Other Factors Affecting Profitability

Other significant factors that can affect our profitability include:

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

Brent crude oil prices averaged $71.04 per barrel in 2018, an increase of 31 percent compared with $54.27 per barrel in 2017. Similarly, WTI crude oil prices increased 28 percent from $50.90 per barrel in 2017 to $64.92 per barrel in the same period of 2018. Crude oil prices improved year over year due to slower growth in global oil production and robust growth in global oil demand. Oil price volatility escalated in the fourth quarter of 2018 due to geopolitics and concerns about future economic growth.

Henry Hub natural gas price averages were relatively unchanged, at $3.09 per million British thermal units (MMBTU) in 2018 compared with $3.11 per MMBTU in 2017. Despite record high natural gas production, prices remained relatively flat year over year as relatively low inventories and strong demand offset production growth.

Our realized natural gas liquids prices averaged $30.48 per barrel in 2018, an increase of 21 percent compared with $25.22 per barrel in 2017, in line with marker movements.

The Western Canada Select (WCS) differential to WTI at Hardisty weakened by $14 per barrel in 2018 relative to 2017 due to a lack of pipeline egress coupled with increasing supply from western Canada. The weaker WCS differential offset year-over-year gains in WTI, resulting in the WCS price

Table of Contents

at Hardisty remaining flat in 2018 compared with 2017 at $39 per barrel. We continue to optimize bitumen price realizations through the utilization of downstream transportation solutions and implementation of alternate blend capability which results in lower diluent costs. Our realized bitumen price was $22.29 per barrel in 2018, a decrease of 2 percent compared with $22.66 per barrel in 2017.

Our worldwide annual average realized price was $53.88 per barrel of oil equivalent (BOE) in 2018, an increase of 37 percent compared with $39.19 per BOE in 2017. The improvement reflects stronger marker prices, as well as a shift in our portfolio toward a higher mix of crude oil and less of bitumen and natural gas.

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

Impairments. We participate in a capital intensive industry. At times, our properties, plants and equipment and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. As we optimize our assets in the future, it is reasonably possible we may incur future losses upon sale or impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. For additional information on our impairments in 2018, 2017 and 2016, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

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

Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments could negatively impact our results of operations, and further changes to increase government fiscal take could have a negative impact on future operations. Our assets in Venezuela were expropriated in 2007. Our production operations in Libya and related oil exports were suspended or significantly curtailed periodically over the last several years due to the closure of the Es Sider crude oil export terminal. In 2016, the U.K. government enacted tax legislation which reduced our U.K. corporate tax rate by 10 percent.

We applied the guidance in Staff Accounting Bulletin (SAB) 118 when accounting for the enactment-date effects of the Tax Cuts and Jobs Act (Tax Legislation) in 2017 and throughout 2018. At December 31, 2017, our assessment was ongoing for the enactment-date income tax effects of the Tax Legislation under Financial Accounting Standards

Board (FASB) Accounting Standards Codification (ASC) Topic 740, Income Taxes, for the following aspects: remeasurement of deferred tax assets and liabilities, one-time transition tax, and tax on global intangible low-taxed income. As of

Table of Contents

December 31, 2018, we have now completed our assessment of the enactment-date income tax effects of the Tax Legislation. During 2018, we recognized adjustments of $10 million to the provisional tax benefit amount of $852 million recorded at December 31, 2017, and included these adjustments as a component of income tax expense. While we still anticipate the Tax Legislation will provide a positive impact to our U.S. operations in the future primarily because of the reduced U.S. federal statutory rate, we do not expect to realize cash tax benefits from the Tax Legislation until we move into a U.S. tax paying position. For additional information, see Note 19 Income Taxes, in the Notes to Consolidated Financial Statements.

Our management carefully considers the fiscal and regulatory environment when evaluating projects or determining the levels and locations of our activity.

Outlook

First-quarter 2019 production is expected to be 1,290 to 1,330 MBOED, reflecting the impacts of a planned turnaround in Qatar of approximately 15 MBOED and government-mandated production curtailment in Canada of approximately 10 MBOED. Production is expected to ramp up in the second half of the year, with full-year 2019 production expected to be 1,300 to 1,350 MBOED. Production guidance for 2019 excludes Libya.

Operating Segments

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

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

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

Table of Contents

RESULTS OF OPERATIONS

Consolidated Results

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

	Millions of Dollars		
Years Ended December 31	**2018**	2017	2016
Alaska	**$ 1,814**	1,466	319
Lower 48	**1,747**	(2,371)	(2,257)
Canada	**63**	2,564	(935)
Europe and North Africa	**1,866**	553	394
Asia Pacific and Middle East	**2,070**	(1,098)	209
Other International	**364**	167	(16)
Corporate and Other	**(1,667)**	(2,136)	(1,329)
Net income (loss) attributable to ConocoPhillips	**$ 6,257**	(855)	(3,615)

2018 vs. 2017

Net income attributable to ConocoPhillips increased $7,112 million in 2018. The increase was mainly due to:

- Higher realized commodity prices on a more liquids-weighted portfolio.
- The absence of a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the marketing of our Barnett asset, recognized in the second quarter of 2017.
- The absence of a $2.4 billion before- and after-tax impairment of our equity investment in Australia Pacific LNG Pty Ltd (APLNG), recognized in the second quarter of 2017.
- Recognition of $774 million after-tax gain on the Clair disposition in the United Kingdom, in the fourth quarter of 2018.
- Lower depreciation, depletion and amortization (DD&A) expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Recognition of $417 million after-tax in other income from a settlement agreement with PDVSA in 2018.
- Lower exploration expenses, primarily due to the absence of first quarter 2017 charges in our Lower 48 and Other International segments.
- Lower interest and debt expense because of a lower debt balance.
- Higher equity earnings in Qatar Liquefied Gas Company Limited (3) (QG3) and APLNG, primarily due to higher realized LNG prices, partly offset by the absence of volumes in 2018 related to the disposition of our interest in the FCCL Partnership in Canada in 2017.

These increases in net income were partly offset by:

The absence of $1.6 billion in after-tax gains related to the sale of certain Canadian assets in 2017.
The absence of a $996 million deferred tax benefit related to the disposition of certain Canadian assets, recognized in the first quarter of 2017.
The absence of deferred tax benefits totaling $852 million related to the Tax Legislation enacted on December 22, 2017.
An unrealized loss of $437 million on our Cenovus Energy common shares in 2018.
The absence of a $337 million after-tax award, including interest, from an arbitration settlement with The Republic of Ecuador in 2017.

Table of Contents

2017 vs. 2016

Loss attributable to ConocoPhillips decreased $2,760 million in 2017. The decrease was mainly due to:

- Higher commodity prices.
- Lower DD&A expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Higher gains on dispositions, primarily due to a $1.6 billion after-tax gain in 2017 on the sale of certain Canadian assets.
- Recognition of deferred tax benefits totaling $996 million, primarily related to the disposition of certain Canadian assets.
- Recognition of deferred tax benefits totaling $852 million related to the Tax Legislation enacted on December 22, 2017.
- Improved equity earnings, mainly due to higher realized prices, lower DD&A from asset disposition impacts, and the absence of a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to the U.S. dollar. These increases were partly offset by lower volumes from the disposition of our interest in the FCCL Partnership.
- Lower exploration expenses mainly due to reduced leasehold impairment expense, dry hole costs and other exploration expenses.
- A $337 million after-tax award, including interest, from an arbitration settlement with The Republic of Ecuador.
- Lower production and operating expenses, primarily due to asset disposition impacts.
- Lower net interest expense, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and reduced debt.

The reduction in loss was partly offset by:

- Higher proved property and equity investment impairments, including a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the marketing of the Barnett, as well as a $2.4 billion before- and after-tax impairment of our equity investment in APLNG.
- Lower volumes primarily due to asset dispositions in our Lower 48, Asia Pacific and Middle East, and Canada segments, as well as normal field decline.
- A $238 million after-tax charge associated with our early retirements of debt in 2017.

Income Statement Analysis

2018 vs. 2017

Sales and other operating revenues increased 25 percent in 2018, due to higher realized commodity prices, mainly crude oil, on a portfolio with a higher mix of crude oil and less of bitumen and natural gas. Partly offsetting this increase, were lower natural gas volumes sold due to 2017 dispositions in the Lower 48 and Canada.

Equity in earnings of affiliates increased $302 million in 2018. The increase in equity earnings was primarily due to higher earnings from QG3 and APLNG as a result of higher LNG prices for both affiliates and higher oil prices in QG3. Partly offsetting this increase, was the absence of equity in earnings resulting from the disposition of our investment in the FCCL Partnership in 2017.

Gain on dispositions decreased $1,114 million in 2018. The decrease was primarily due to the absence of a $2.1 billion before-tax gain on the sale of certain Canadian assets recognized in 2017, partly offset by a $715 million before-tax gain recognized in the fourth quarter of 2018 on the sale of a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. For additional information concerning gain on dispositions, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Table of Contents

Other income decreased $356 million in 2018, mainly due to a $437 million unrealized loss on our Cenovus Energy common shares in 2018 and the absence of a $337 million arbitration settlement, including interest, with The Republic of Ecuador in 2017. Partly offsetting the decrease, was $430 million before-tax from a settlement agreement with PDVSA in 2018.

For discussion of our Cenovus Energy shares, see Note 7 Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements. For discussion of our Ecuador and PDVSA settlements, see Note 13 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Purchased commodities increased 15 percent in 2018, mainly due to higher crude oil volumes purchased and higher crude oil prices.

Production and operating expenses increased 1 percent in 2018, primarily due to costs associated with higher underlying production volumes as well as higher maintenance and wellwork, largely offset by the absence of costs resulting from 2017 dispositions in our Canada and Lower 48 segments.

Exploration expenses decreased $565 million in 2018, primarily as a result of lower dry hole costs, leasehold impairment expense and other exploration expenses.

Dry hole costs were reduced primarily due to the absence of before-tax charges of $288 million for multiple Shenandoah wells in the deepwater Gulf of Mexico, including wells previously suspended. These charges were reflected in our Lower 48 segment during 2017.

Leasehold impairment expense was reduced mainly due to the absence of before-tax charges of $51 million for Shenandoah and $38 million for certain Lower 48 mineral assets, both recognized in 2017.

Other exploration expenses were reduced mainly due to the absence of a $43 million before-tax charge for the cancellation of our Athena drilling rig contract and other rig stacking costs in our Other International segment in 2017.

For additional information on leasehold impairments and other exploration expenses, see Note 8 Suspended Wells and Other Exploration Expenses, and Note 9 Impairments, in the Notes to Consolidated Financial Statements.

DD&A decreased $889 million in 2018, mainly due to lower unit-of-production rates from positive reserve revisions and impacts from the 2017 dispositions in our Canada and Lower 48 segments, partly offset by increased underlying production volumes.

Impairments decreased $6.6 billion in 2018, mainly due to the absence of 2017 impairments of $3.9 billion before-tax related to our former interests in the San Juan Basin and the Barnett, both in our Lower 48 segment, as well as a $2.4 billion before- and after-tax impairment of our equity investment in APLNG. For additional information, see Note 6 Investments, Loans and Long-Term Receivables and Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes increased $239 million in 2018, primarily due to higher production taxes in Alaska and the Lower 48 corresponding with higher realized commodity prices.

Interest and debt expense decreased $363 million in 2018, primarily due to lower debt balances.

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

Table of Contents

2017 vs. 2016

Sales and other operating revenues increased 23 percent in 2017, mainly due to higher realized prices across all commodities, partly offset by lower sales volumes, primarily in our Lower 48, Asia Pacific and Middle East, and Canada segments as a result of dispositions.

Equity in earnings of affiliates increased $720 million in 2017. The increase in equity earnings was primarily due to higher realized commodity prices at QG3, APLNG and FCCL; the absence of a 2016 deferred tax charge of $174 million resulting from a tax functional currency change; and reduced costs mainly from the disposition of our interest in the FCCL Partnership. The increase in earnings was partly offset by lower volumes as a result of our FCCL disposition.

Gain on dispositions increased $1.8 billion in 2017. The increase was primarily due to a before-tax gain of $2.1 billion on the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets. For additional information on gains on dispositions, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, in the Notes to Consolidated Financial Statements.

Other income increased $274 million in 2017, mainly due to a $337 million before- and after-tax arbitration award from The Republic of Ecuador. The increase was partly offset by the absence of a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust and a $76 million before-tax damage claim settlement, both in our Lower 48 segment in 2016.

Purchased commodities increased 25 percent in 2017, mainly due to higher commodity prices and increased activity.

Selling, general and administrative expenses decreased 10 percent in 2017, primarily due to reduced restructuring expenses, lower headcount and reduced activity.

Exploration expenses decreased 51 percent in 2017, primarily as a result of lower leasehold impairment expense, dry hole costs and other exploration expenses.

Leasehold impairment expense was reduced mainly due to the absence of 2016 before-tax charges of $203 million for our Gibson and Tiber leaseholds. The expense was further reduced by the absence of before-tax charges of $95 million for our Melmar leasehold and $79 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by a before-tax charge of $51 million for Shenandoah in deepwater Gulf of Mexico and a before-tax charge of $38 million for certain mineral assets in our Lower 48 segment, both in 2017.

Dry hole costs were reduced primarily due to the absence of 2016 before-tax charges in deepwater Gulf of Mexico of $249 million for our Gibson and Tiber wells, and $128 million for our Melmar well. The absence of a $256 million before-tax charge in 2016 for two dry holes in Nova Scotia further reduced costs. The reduction in dry hole costs was partly offset by 2017 before-tax charges of $288 million for multiple wells in Shenandoah, including wells previously suspended, and $63 million for several wells in the Powder River Basin.

Other exploration expenses were reduced mainly due to the absence of a $146 million before-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract, as well as lower rig stacking costs in Angola. The decrease in expense was partly offset by a $43 million net before-tax charge in 2017 for the settlement of our drilling rig contract in Angola.

For additional information on leasehold impairments and other exploration expenses, see Note 8 Suspended Wells and Other Exploration Expenses, and Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Table of Contents

DD&A decreased 24 percent in 2017, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts in our Canada and Lower 48 segments.

Impairments increased $6.5 billion in 2017. For additional information, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Interest and debt expense decreased 12 percent in 2017, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and reduced debt balances.

Other expenses included before-tax charges of $302 million in 2017 for premiums on early debt retirements.

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

Summary Operating Statistics

		2018	2017	2016
Average Net Production				
Crude oil (MBD)[1]		**653**	599	598
Natural gas liquids (MBD)		**102**	111	145
Bitumen (MBD)		**66**	122	183
Natural gas (MMCFD)[2]		**2,774**	3,270	3,857
Total Production (MBOED)[3]		**1,283**	1,377	1,569
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per barrel)	$	**68.13**	51.96	40.86
Natural gas liquids (per barrel)		**30.48**	25.22	16.68
Bitumen (per barrel)		**22.29**	22.66	15.27
Natural gas (per thousand cubic feet)		**5.65**	4.07	3.00
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical, lease rental, and other[4]	$	**274**	368	728
Leasehold impairment		**56**	136	466
Dry holes		**39**	430	718
	$	**369**	934	1,912

(1)Thousands of barrels per day.

(2)Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.

(3)Thousands of barrels of oil equivalent per day.

(4)Certain prior period amounts in 2017 and 2016 have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07.

See Note 2   Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2018, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Table of Contents

2018 vs. 2017

Total production, including Libya, of 1,283 MBOED decreased 7 percent in 2018 compared with 2017, primarily due to:

- Disposition impacts from asset sales in Canada and the Lower 48 in 2017.
- Normal field decline.
- Higher unplanned downtime, including a third-party pipeline outage in Malaysia in 2018.

The decrease in production during 2018 was partly offset by:

- New wells online, primarily from tight oil plays in the Lower 48 and Malikai in Malaysia.
- Improved drilling and well performance in Alaska, Norway, Lower 48 and China.
- The continued rampup in Libya.

Production excluding Libya was 1,242 MBOED in 2018 compared with 1,356 MBOED in 2017. The volume from closed dispositions was approximately 200 MBOED in 2017 and 15 MBOED in 2018. The volume from acquisitions was less than 10 MBOED in 2018. Our underlying production, which excludes the full-year impact of acquisitions, dispositions, and Libya, increased over 5 percent in 2018 compared with 2017.

2017 vs. 2016

Total production, including Libya, of 1,377 MBOED decreased 12 percent in 2017 compared with 2016, primarily due to:

- Reductions from noncore asset dispositions, including Canada and the Lower 48 in 2017 and the sale of our interest in the Block B production sharing contract in Indonesia in 2016.
- Normal field decline.

The decrease in production during 2017 was partly offset by:

- Production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont in Canada; and APLNG in Australia.
- Improved drilling and well performance in Alaska, Norway and China.

Excluding Libya, our 2017 production was 1,356 MBOED. Adjusted for the impact of closed and planned dispositions of 191 MBOED in 2017 and 434 MBOED in 2016 and Libya, our underlying production increased 32 MBOED, or 3 percent, compared with 2016.

Table of Contents

Alaska

		2018	2017	2016
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**1,814**	1,466	319
Average Net Production				
Crude oil (MBD)		**171**	167	163
Natural gas liquids (MBD)		**14**	14	12
Natural gas (MMCFD)		**6**	7	25
Total Production (MBOED)		**186**	182	179
Average Sales Prices				
Crude oil (per barrel)	$	**70.86**	53.33	41.93
Natural gas (per thousand cubic feet)		**2.48**	2.72	5.22

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids and natural gas. In 2018, Alaska contributed 23 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

2018 vs. 2017

Alaska reported earnings of $1,814 million in 2018, compared with earnings of $1,466 million in 2017. The increase in earnings was mainly due to higher realized crude oil prices. Additionally, earnings were improved due to the absence of a $110 million after-tax impairment related to our small interest in the Point Thomson Unit, recognized in the first quarter of 2017; a $98 million reduction in tax valuation allowance, recognized in the fourth quarter of 2018; lower DD&A expense from reserve additions; and a $79 million after-tax benefit resulting from an accrual reduction due to a transportation cost ruling by the Federal Energy Regulatory Commission (FERC), recorded in the first quarter of 2018. Partly offsetting these increases in earnings, was the absence of an $892 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation enacted in 2017.

Average production increased 2 percent in 2018 compared with 2017, primarily due to improved drilling and well performance, 8 MBOED from acquisitions in the Western North Slope and the Greater Kuparuk Area, and the startup of GMT-1 in the fourth quarter of 2018, partly offset by normal field decline.

Acquisitions

During the second quarter of 2018, we obtained regulatory approvals and completed a transaction with Anadarko Petroleum Corporation to acquire its 22 percent nonoperated interest in the Western North Slope of Alaska, as well as its interest in the Alpine Transportation Pipeline, for $386 million, after customary adjustments. In 2018, our Alaska segment net production included 7 MBOED associated with the additional interest acquired. In addition, we now have

100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow Discovery.

In December of 2018, we completed a transaction with BP to acquire their nonoperated interest in the Kuparuk Assets in Alaska, and to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. In 2018, our Alaska segment net production included 1 MBOED related to the additional interest acquired in the Greater Kuparuk Area. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Table of Contents

2017 vs. 2016

Alaska reported earnings of $1,466 million in 2017, compared with earnings of $319 million in 2016. The increase in earnings was mainly due to an $892 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation. Earnings were additionally improved due to higher crude oil prices in 2017. The earnings increase was partly offset by a $110 million after-tax impairment charge for the associated properties, plants and equipment of our small interest in the Point Thomson unit.

Average production increased 2 percent in 2017 compared with 2016, as the impact of normal field decline was more than offset by well performance in the Western North Slope, Greater Prudhoe and Greater Kuparuk areas and lower unplanned downtime.

Lower 48

		2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$	**1,747**	(2,371)	(2,257)
Average Net Production				
Crude oil (MBD)		**229**	180	195
Natural gas liquids (MBD)		**69**	69	88
Natural gas (MMCFD)		**596**	898	1,219
Total Production (MBOED)		**397**	399	486
Average Sales Prices				
Crude oil (per barrel)	$	**62.99**	47.36	37.49
Natural gas liquids (per barrel)		**27.30**	22.20	14.34
Natural gas (per thousand cubic feet)		**2.82**	2.73	2.20

The Lower 48 segment consists of operations located in the contiguous United States and the Gulf of Mexico. During 2018, the Lower 48 contributed 36 percent of our worldwide liquids production and 21 percent of our natural gas production.

2018 vs. 2017

Lower 48 reported earnings of $1,747 million in 2018, compared with a net loss of $2,371 million in 2017. Earnings increased primarily due to the absence of a combined $2.5 billion after-tax impairment related to the sale of our interests in the San Juan Basin and the marketing of our Barnett asset, recognized in the second quarter of 2017; higher realized crude oil and NGL prices; higher crude oil sales volumes; lower DD&A expense, primarily due to reserve additions and asset disposition impacts, partly offset by higher underlying volumes; lower exploration expenses and higher gain on dispositions related to noncore asset sales. The increase in earnings was partly offset by lower natural gas sales volumes, primarily due to the disposition of our interests in the San Juan Basin in 2017.

In 2018, our average realized crude oil price of $62.99 per barrel was 3 percent less than WTI of $64.92 per barrel. The differential was driven primarily by local market dynamics in the Gulf Coast, Bakken and Permian Basin.

Table of Contents

Total average production decreased 1 percent in 2018 compared with 2017. The decrease was mainly attributable to normal field decline and disposition impacts related to interests sold in the San Juan Basin and other noncore assets. Adjusted for the impact of dispositions of 82 MBOED in 2017, underlying production increased approximately 25 percent in 2018 compared with 2017, primarily due to new production from unconventional assets in the Eagle Ford, Bakken and Permian Basin.

Asset Dispositions and Other Planned Disposition

In the first quarter of 2018, we completed the sale of certain properties in the Lower 48 segment for net proceeds of $112 million. No gain or loss was recognized on the sale. In the second quarter of 2018, we completed the sale of a package of largely undeveloped acreage for net proceeds of $105 million. No gain or loss was recognized on the sale. In the third quarter of 2018, we completed a noncash exchange of undeveloped acreage in the Lower 48 segment. This transaction was recorded at fair value resulting in the recognition of a $44 million after-tax gain. In the fourth quarter of 2018, we sold several packages of undeveloped acreage in the Lower 48 segment for total net proceeds of $162 million and recognized gains of approximately $140 million.

In the fourth quarter of 2018, we completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments. Production associated with the Barnett averaged 8 MBOED in 2018, of which approximately 55 percent was natural gas and 45 percent was natural gas liquids. After-tax impairment charges of $69 million were recognized during 2018.

In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in Golden Pass LNG Terminal and Golden Pass Pipeline located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal and pipeline capacity was held for receipt, storage and regasification of LNG purchased from QG3. As a result of entering into these agreements, we expect to recognize a loss of approximately $60 million in the first quarter of 2019. We have also entered into agreements to amend our contractual obligations for remaining use of the facilities. Completion of the sale is subject to regulatory approval.

See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Acquisition

We began acquiring early life-cycle acreage in the Austin Chalk in the fourth quarter of 2017 and have accumulated approximately 225,000 net acres at less than $1,000 per acre. We spud our first Austin Chalk well in late 2018 and plan to drill additional wells in 2019.

2017 vs. 2016

Lower 48 reported a loss of $2,371 million after-tax in 2017, compared with a loss of $2,257 million after-tax in 2016. The increase in loss was primarily due to proved property impairments in 2017, totaling $2.5 billion after-tax, for our interests in the San Juan Basin and the Barnett which were written down to fair value less costs to sell. Lower natural gas, crude oil and natural gas liquids sales volumes from asset dispositions and normal field decline further increased losses during the year.

Table of Contents

The increase in losses was partly offset by:

Lower DD&A expense, mainly resulting from a lower unit-of-production rate from reserve revisions, disposition impacts and lower volumes.
A $689 million tax benefit, primarily related to the revaluation of allocated U.S. deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation enacted in 2017.
Higher realized crude oil, natural gas liquids and natural gas prices.
Lower exploration expenses mainly due to:

- Lower leasehold impairment expense, primarily the absence of 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds; $62 million for our Melmar leasehold and $52 million for various Gulf of Mexico leases after completion of marketing efforts. The reduction was partly offset by an after-tax charge of $33 million for Shenandoah in deepwater Gulf of Mexico and an after-tax charge of $24 million for certain mineral assets, both in 2017.
- Lower other exploration expenses, mainly due to the absence of a $95 million after-tax expense in 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract.
- Lower dry hole costs primarily due to the absence of 2016 after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells, and $83 million for our Melmar well, partly offset by 2017 after-tax charges of $187 million for multiple wells in Shenandoah and $41 million for several wells in the Powder River Basin.

In 2017, our average realized crude oil price of $47.36 per barrel was 7 percent less than WTI of $50.90 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast and Bakken.

Total average production decreased 18 percent in 2017 compared with 2016. The decrease was mainly attributable to normal field decline and the disposition of our interests in the San Juan Basin, partly offset by new production, primarily from Eagle Ford and Bakken.

Asset Dispositions

On July 31, 2017, we completed the sale of our interests in the San Juan Basin for total proceeds comprised of $2.5 billion in cash after customary adjustments and a contingent payment of up to $300 million. The six-year contingent payment, effective beginning January 1, 2018, is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units. During 2018, we recorded gains on dispositions for these contingent payments of $28 million.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Table of Contents

Canada

		2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$	**63**	2,564	(935)
Average Net Production				
Crude oil (MBD)		**1**	3	7
Natural gas liquids (MBD)		**1**	9	23
Bitumen (MBD)				
Consolidated operations		**66**	59	35
Equity affiliates		**-**	63	148
Total bitumen		**66**	122	183
Natural gas (MMCFD)		**12**	187	524
Total Production (MBOED)		**70**	165	300
Average Sales Prices				
Crude oil (per barrel)	$	**48.73**	43.69	35.25
Natural gas liquids (per barrel)		**43.70**	21.51	14.82
Bitumen (dollars per barrel)*				
Consolidated operations		**22.29**	21.43	12.91
Equity affiliates		**-**	23.83	15.80
Total bitumen		**22.29**	22.66	15.27
Natural gas (per thousand cubic feet)		**1.00**	1.93	1.49

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

Our Canadian operations mainly consist of an oil sands development in the Athabasca region of northeastern Alberta and a liquids-rich unconventional play in western Canada. In 2018, Canada contributed 8 percent of our worldwide liquids production and less than one percent of our worldwide natural gas production.

2018 vs. 2017

Canada operations reported earnings of $63 million in 2018 compared with $2,564 million in 2017. The decrease was mainly due to the absence of a $1.6 billion after-tax gain on the sale of our interest in the FCCL Partnership and western Canada gas assets and an associated $1.0 billion deferred tax benefit, and equity earnings in the FCCL Partnership. For additional information on the Canada disposition, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions and Note 7 Investment in Cenovus Energy, in the Notes to Consolidated Financial

Statements.

Total average production decreased 95 MBOED in 2018 compared with 2017. The production decrease was primarily due to our 2017 Canada disposition, partly offset by strong well performance at Surmont.

Acquisition

In February 2018, we acquired approximately 34,500 net acres of undeveloped land in the Montney for a net purchase price of approximately $120 million. The additional acreage is adjacent to our existing position in the liquids-rich portion of the Montney.

Table of Contents

2017 vs. 2016

Canada operations reported earnings of $2,564 million in 2017, an increase of $3,499 million compared with 2016. The earnings increase was mainly due to an after-tax gain of $1.6 billion on the sale of certain Canadian assets, further discussed below, as well as the recognition of $1.0 billion in deferred tax benefits related to the capital gains component of our disposition and the recognition of previously unrealizable Canadian tax basis.

In addition to the items discussed above, earnings were further increased due to:

- Lower DD&A, mainly from disposition impacts.
- Lower dry hole costs, mainly due to the absence of 2016 combined after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.
- Higher realized prices across all commodities.
- A $114 million tax benefit related to our prior decision to exit Nova Scotia deepwater exploration.
- Lower production and operating expenses.
- Improved equity earnings, as improved prices and reduced DD&A more than offset the volume loss from our Canada disposition.

The earnings increase was partly offset by additional volume reductions from the disposition of our western Canada gas assets.

Total average production decreased 45 percent in 2017 compared with 2016. The production decrease was primarily due to the Canada disposition, partly offset by production rampup at Surmont.

Asset Disposition

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11.0 billion in cash after customary adjustments, 208 million Cenovus Energy common shares and a five-year uncapped contingent payment. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the WCS quarterly average crude price exceeds $52 CAD per barrel. During 2018, we recorded gains on dispositions for these contingent payments of $95 million. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Europe and North Africa

		2018	2017	2016
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**1,866**	553	394
Average Net Production				
Crude oil (MBD)		**149**	142	122

Natural gas liquids (MBD)	**8**	8	7
Natural gas (MMCFD)	**503**	484	460
Total Production (MBOED)	**241**	230	205
Average Sales Prices			
Crude oil (dollars per barrel)	**$ 70.71**	54.21	43.66
Natural gas liquids (per barrel)	**36.87**	34.07	22.62
Natural gas (per thousand cubic feet)	**7.65**	5.70	4.71

Table of Contents

The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea and Libya. In 2018, our Europe and North Africa operations contributed 19 percent of our worldwide liquids production and 18 percent of our natural gas production.

2018 vs. 2017

Earnings for Europe and North Africa operations of $1,866 million increased $1,313 million in 2018 compared to 2017. Earnings in 2018 included a $774 million after-tax gain related to the sale of a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. Earnings were also improved due to higher realized crude oil and natural gas prices and lower DD&A expense, primarily due to reserve additions.

Average production increased 5 percent in 2018, compared with 2017. The increase was mainly due to higher production in Libya and new wells online in Norway and the United Kingdom. These increases in production were partly offset by normal field decline and the final cessation of production in several producing gas fields in the Southern North Sea in the third quarter of 2018. Production associated with the Southern North Sea was 22 million cubic feet a day or 4 MBOED in 2018.

Dispositions

In the fourth quarter of 2018, we completed a transaction to sell a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom and acquire their nonoperated interest in the Kuparuk Assets in Alaska. In 2018, our Europe and North Africa segment net production associated with the disposed 16.5 percent interest in the Clair Field was approximately 5 MBOED. We recognized a $774 million after-tax gain in the fourth quarter related to this transaction, as discussed above. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions in the Notes to Consolidated Financial Statements, for additional information.

We are currently marketing our United Kingdom Business Unit.

2017 vs. 2016

Earnings for Europe and North Africa operations of $553 million increased 40 percent in 2017. The increase in earnings was primarily due to higher realized crude oil, natural gas and natural gas liquids prices. Earnings were additionally improved by lower DD&A, mainly due to reserve revisions; a $60 million tax benefit from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the Tax Legislation; and a $41 million tax benefit in Norway.

The increase in earnings was partly offset by the absence of a 2016 net deferred tax benefit of $161 million resulting from a change in the U.K. tax rate and a lower credit to impairment in 2017, compared with 2016, reflecting the annual updates to ARO on fields at or nearing the end of life which were impaired in prior years. The earnings improvement was further reduced by a net deferred tax charge of $65 million in the U.K. resulting from updated assumptions regarding applicable tax rates.

Average production increased 12 percent in 2017, compared with 2016. The increase was mainly due to the resumption and rampup of production in Libya; improved drilling and well performance in Norway; new production from the Greater Britannia Area and Norway; and higher Norway gas offtake, partly offset by normal field decline.

Table of Contents

Asia Pacific and Middle East

	2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$ **2,070**	(1,098)	209
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**89**	93	97
Equity affiliates	**14**	14	14
Total crude oil	**103**	107	111
Natural gas liquids (MBD)			
Consolidated operations	**3**	4	7
Equity affiliates	**7**	7	8
Total natural gas liquids	**10**	11	15
Natural gas (MMCFD)			
Consolidated operations	**626**	687	730
Equity affiliates	**1,031**	1,007	899
Total natural gas	**1,657**	1,694	1,629
Total Production (MBOED)	**389**	401	399
Average Sales Prices			
Crude oil (dollars per barrel)			
Consolidated operations	$ **70.93**	54.38	42.23
Equity affiliates	**72.49**	54.76	44.11
Total crude oil	**71.14**	54.43	42.47
Natural gas liquids (dollars per barrel)			
Consolidated operations	**47.20**	41.37	29.00
Equity affiliates	**45.69**	38.74	31.13
Total natural gas liquids	**46.13**	39.75	30.11
Natural gas (dollars per thousand cubic feet)			
Consolidated operations	**6.15**	4.98	4.31
Equity affiliates	**6.06**	4.27	2.97
Total natural gas	**6.09**	4.55	3.57

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar. During 2018, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 60 percent of our natural gas production.

2018 vs. 2017

Asia Pacific and Middle East reported earnings of $2,070 million in 2018, compared with a loss of $1,098 million in 2017. The increase in earnings was mainly due to the absence of a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in 2017, higher realized commodity prices, and increased equity in earnings of affiliates, mainly due to higher LNG prices. See the APLNG section of Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on the 2017 impairment of our APLNG investment.

Average production decreased 3 percent in 2018, compared with 2017. The decrease was primarily due to unplanned downtime in Malaysia related to the rupture of a third-party pipeline which carries gas production from the Kebabangan gas field in Malaysia and normal field decline. This decrease was partly offset by new wells online at Malakai in Malaysia and an infill drilling program in China.

Asset Disposition

In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals. No production or reserve impacts are associated with the sale.

2017 vs. 2016

Asia Pacific and Middle East reported a loss of $1,098 million in 2017, compared with earnings of $209 million in 2016. The increase in loss was mainly due to a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in 2017. For additional information on our APLNG impairment, see the APLNG section of Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. Additionally, lower sales volumes in Indonesia, Australia and China further increased losses.

The increase in losses was partly offset by higher equity earnings, mainly as a result of higher commodity prices, increased sales volumes at APLNG and the absence of a 2016 deferred tax charge of $174 million resulting from the change of our APLNG tax functional currency. Higher realized crude oil and natural gas prices on non-equity volumes further reduced the loss.

Average production was essentially flat in 2017.

Other International

		2018	2017	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$**	**364**	167	(16)

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

2018 vs. 2017

Other International operations reported earnings of $364 million in 2018, compared with earnings of $167 million in 2017. The increase in earnings was primarily due to recognizing $417 million after-tax in other income under a settlement agreement with PDVSA associated with an arbitration award issued by the ICC. Partly offsetting the increase in earnings, was the absence of a $320 million after-tax award from an arbitration settlement with The Republic of Ecuador in 2017. See Note 13 Contingencies and Commitments in the Notes to Consolidated Financial Statements, for additional information.

New Country Entrance

We received approval from Argentina s government in January 2019 for a 50 percent nonoperated interest in the El Turbio Este block in the Austral Basin.

2017 vs. 2016

Other International operations reported earnings of $167 million in 2017, compared with a loss of $16 million in 2016. The increase in earnings was primarily due to a $320 million after-tax International Centre for Settlement of Investment Disputes (ICSID) award from an arbitration with The Republic of Ecuador. Earnings were additionally increased due to lower rig stacking costs in Angola. The increase in earnings was partly

56

Table of Contents

offset by the absence of a $138 million gain in 2016 on the disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal, and a $45 million tax charge from the revaluation of allocated U.S. deferred taxes at a lower U.S. federal statutory rate, in accordance with the Tax Legislation.

Corporate and Other

	Millions of Dollars		
	2018	2017	2016
Net Loss Attributable to ConocoPhillips			
Net interest	$ **(680)**	(739)	(980)
Corporate general and administrative expenses	**(91)**	(193)*	(147)*
Technology	**109**	20	50
Other	**(1,005)**	(1,224)*	(252)*
	$ **(1,667)**	(2,136)	(1,329)

**Certain amounts have been reclassified to reflect the adoption of ASU No. 2017-07. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information.*

2018 vs. 2017

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased $59 million in 2018 compared with 2017, primarily due to less interest from lower debt balances, higher capitalized interest on projects, and an accrual reduction due to a transportation cost ruling by the FERC in the first quarter of 2018. Partly offsetting these impacts, were reduced tax benefits on interest expense following the Tax Legislation, which lowered the U.S. corporate income tax rate from 35 percent to 21 percent effective January 1, 2018, and a lower tax benefit due to higher interest from the fair market value method of apportioning interest expense in the United States.

Corporate general and administrative expenses include compensation programs and staff costs. These costs decreased by $102 million in 2018 compared with 2017, primarily due to lower staff expenses and costs associated with certain key employee compensation programs.

Technology includes our investment in new technologies or businesses, as well as licensing revenues. Activities are focused on tight oil reservoirs, LNG, oil sands and other production operations. Earnings from Technology increased by $89 million in 2018 compared with 2017, primarily due to higher licensing revenues. See Note 24 Sales and Other Operating Revenues, in the Notes to Consolidated Financial Statements, for additional information.

The category Other includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment, premiums incurred on the early retirement of debt, unrealized holding gains or losses on equity securities, and pension settlement expense. Losses in Other decreased by $219 million in 2018 compared with 2017, primarily due to the absence of an $813 million tax charge from the revaluation of deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation enacted in 2017; lower premiums on the early retirement of debt; partly offset by a $437 million unrealized loss on our Cenovus Energy common shares.

Table of Contents

2017 vs. 2016

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased 25 percent in 2017 compared with 2016, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest as a result of reduced debt. Higher interest income further drove the decrease in net interest, which was partly offset by lower capitalized interest on projects.

Corporate general and administrative expenses which include pension settlement expenses and compensation program costs increased $46 million in 2017 compared with 2016, primarily due to higher costs associated with certain key employee compensation programs and staff expenses. See Note 2 Changes in Accounting Principles, in the Notes to Financial Statements, for additional information.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, LNG, oil sands and other production operations. Earnings from Technology were $20 million in 2017, compared with $50 million in 2016. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

The category Other includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment and premiums incurred on the early retirement of debt. Losses in Other increased $972 million in 2017, mainly due to an $813 million tax charge from the revaluation of deferred taxes at a lower federal statutory rate, in accordance with the Tax Legislation and premiums on our early retirement of debt.

Table of Contents

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars Except as Indicated		
		2018	2017	2016
Net cash provided by operating activities	$	**12,934**	7,077	4,403
Cash and cash equivalents		**5,915**	6,325	3,610
Short-term debt		**112**	2,575	1,089
Total debt		**14,968**	19,703	27,275
Total equity		**32,064**	30,801	35,226
Percent of total debt to capital*		**32%**	39	44
Percent of floating-rate debt to total debt		**5%**	5	9

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, proceeds from asset sales, our commercial paper and credit facility programs and our ability to sell securities using our shelf registration statement. In 2018, the primary uses of our available cash were $6,750 million to support our ongoing capital expenditures and investments program; $4,995 million to reduce debt; $2,999 million to repurchase our common stock; and $1,363 million to pay dividends on our common stock. During 2018, cash, cash equivalents, and restricted cash decreased by $385 million to $6,151 million.

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

Significant Sources of Capital

Operating Activities

During 2018, cash provided by operating activities was $12,934 million, an 83 percent increase from 2017. The increase was primarily due to higher realized commodity prices and higher distributions from equity affiliates.

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

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Full-year production averaged 1,283 MBOED in 2018. Full-year production excluding Libya averaged 1,242 MBOED in 2018 and is expected to be 1,300 to 1,350 MBOED in 2019. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies; timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes on an ongoing basis, we must continue to add to our proved reserve base. Our proved reserves generally increase as prices rise and decrease as prices decline. In 2018, our reserve replacement, which included a net increase of 0.2 billion BOE from sales and purchases, was 147 percent. Increased crude oil reserves accounted for over 90 percent of the total change in reserves. Our organic reserve replacement, which excludes the impact of sales and purchases, was 109 percent in 2018. Approximately 33 percent of organic reserve additions are from Lower 48 unconventional assets, 29 percent from Alaska and 22 percent from Asia Pacific and Middle East.

In the five years ended December 31, 2018, our reserve replacement, which included a decrease of 2.1 billion BOE from sales and purchases, was negative 30 percent, reflecting the impact of asset dispositions and lower prices during that period. Our organic reserve replacement during the five years ended December 31, 2018, was 44 percent, reflecting development activities as well as lower prices during that period.

Reserve replacement represents the net change in proved reserves, net of production, divided by our current year production, as shown in our supplemental reserve table disclosures. For additional information about our 2019 capital budget, see the 2019 Capital Budget section within Capital Resources and Liquidity and for additional information on proved reserves, including both developed and undeveloped reserves, see the Oil and Gas Operations section of this report.

As discussed in the Critical Accounting Estimates section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2018 and 2017, revisions increased reserves, while in 2016, revisions decreased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Investing Activities

Proceeds from asset sales in 2018 were $1.1 billion. We completed several undeveloped acreage transactions in our Lower 48 segment for a total of $267 million after customary adjustments and another transaction in our Lower 48 segment for $112 million after customary adjustments. We completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments. We also received $253 million net proceeds for customary adjustments related to our transaction with BP for the disposition of a ConocoPhillips subsidiary holding a 16.5 percent interest in the Clair Field in the United Kingdom and the acquisition of the Kuparuk Assets. We received contingent payments of $95 million in relation to our 2017 Canada disposition to Cenovus Energy.

Proceeds from asset sales in 2017 were $13.9 billion. We completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included $11.0 billion in cash after customary adjustments and 208 million Cenovus Energy common shares. We completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company. Total proceeds for the sale were $2.5 billion in cash after customary adjustments. We also completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

For additional information on our dispositions and investment in Cenovus common shares, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions and Note 7 Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, and the Results of Operations section within Management s Discussion and Analysis.

Commercial Paper and Credit Facilities

In May 2018, we refinanced our revolving credit facility from a total aggregate principal amount of $6.75 billion to $6.0 billion with a new expiration date of May 2023. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper program. The revolving credit facility is broadly syndicated among financial institutions

60

and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

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

The revolving credit facility supports the ConocoPhillips Company $6.0 billion commercial paper program which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding in programs in place at December 31, 2018 or December 31, 2017. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at December 31, 2018 and December 31, 2017. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.0 billion in borrowing capacity under our revolving credit facility at December 31, 2018.

In August 2018, Fitch upgraded our long-term debt rating from A- to A and adjusted their outlook for our debt from positive to stable. In September 2018, Moody s Investors Services upgraded its rating on our long-term debt from Baa1 to A3 and adjusted its outlook for our debt from positive to stable. In November 2018, Standard & Poor s upgraded o long-term debt rating from A- to A, with a stable outlook. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. If our credit rating were downgraded, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2018 and 2017, we had direct bank letters of credit of $323 million and $338 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of credit ratings downgrades, we may be required to post additional letters of credit.

Shelf Registration

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

Off-Balance Sheet Arrangements

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

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

Table of Contents

Capital Requirements

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

Our debt balance at December 31, 2018, was $15.0 billion, a decrease of $4.7 billion from the balance at December 31, 2017. We achieved our stated debt target of $15 billion eighteen months earlier than the original target date of year-end 2019.

In 2018, we repaid the $250 million floating rate note due in 2018 at its natural maturity. We also redeemed or repurchased a total $4,450 million of debt, described below, incurring $208 million in net premiums above book value, which are reported in the Other expenses line on our consolidated income statement.

- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.
- 2.4% Notes due 2022 with principal of $1.0 billion (partial repurchase of $671 million).
- 3.35% Notes due 2024 with principal of $1.0 billion (partial repurchase of $574 million).
- 2.2% Notes due 2020 with principal of $500 million.
- 3.35% Notes due 2025 with principal of $500 million (partial repurchase of $301 million).
- 4.15% Notes due 2034 with principal of $500 million (partial repurchase of $254 million).
- 8.125% Notes due 2030 with principal of $600 million (partial repurchase of $210 million).
- 7.8% Notes due 2027 with principal of $300 million (partial repurchase of $97 million).
- 7.9% Notes due 2047 with principal of $100 million (partial repurchase of $40 million).
- 9.125% Notes due 2021 with principal of $150 million (partial repurchase of $27 million).
- 8.20% Notes due 2025 with principal of $150 million (partial repurchase of $16 million).
- 7.65% Notes due 2023 with principal of $88 million (partial repurchase of $10 million).

For more information on Debt, see Note 11 Debt, in the Notes to Consolidated Financial Statements.

On February 1, 2018, we announced an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share. The dividend was paid on March 1, 2018, to stockholders of record at the close of business on February 12, 2018. On May 4, 2018, we announced a quarterly dividend of $0.285 per share. The dividend was paid on June 1, 2018, to stockholders of record at the close of business on May 14, 2018. On July 11, 2018, we announced a quarterly dividend of $0.285 per share. The dividend was paid on September 4, 2018, to stockholders of record at the close of business on July 23, 2018. On October 5, 2018, we announced a 7 percent increase in the quarterly dividend to $0.305 per share. The dividend was paid on December 3, 2018, to stockholders of record at the close of business on October 15, 2018. On January 30, 2019, we announced a quarterly dividend of $0.305 cents per share, payable March 1, 2019, to stockholders of record at the close of business on February 11, 2019.

In late 2016, we initiated our current share repurchase program. As of June 30, 2018, we had announced authorization to repurchase a total of $6 billion of our common stock. We repurchased $3 billion in 2017 and $3 billion in 2018. On July 12, 2018, we announced an authorization of an additional $9 billion in share repurchases bringing the total program authorization to $15 billion. We expect to execute $3 billion of the remaining $9 billion of our share repurchase program in 2019. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, market conditions and other factors. See Risk Factors Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Since our share repurchase program began in November 2016, we have repurchased 111 million shares at a cost of $6.1 billion through December 31, 2018.

During the third quarter of 2017, we made a $600 million contribution to our domestic qualified pension plan, which is included in the Other line in the Cash Flows From Operating Activities section of our consolidated statement of cash flows. This additional contribution lowered our domestic pension deficit, thereby reducing 2018 premiums charged by the Pension Benefit Guaranty Corporation.

Table of Contents

Contractual Obligations

The table below summarizes our aggregate contractual fixed and variable obligations as of December 31, 2018:

		Millions of Dollars				
		Payments Due by Period				
		Total	Up to 1 Year	Years 2 3	Years 4 5	After 5 Years
Debt obligations (a)	$	14,191	33	159	987	13,012
Capital lease obligations (b)		777	79	155	143	400
Total debt		14,968	112	314	1,130	13,412
Interest on debt and other obligations		12,213	865	1,710	1,634	8,004
Operating lease obligations (c)		1,394	248	561	373	212
Purchase obligations (d)		9,703	4,000	1,854	1,422	2,427
Other long-term liabilities						
Pension and postretirement benefit contributions (e)		1,519	380	634	505	
Asset retirement obligations (f)		7,908	378	672	681	6,177
Accrued environmental costs (g)		178	20	28	26	104
Unrecognized tax benefits (h)		115	115	(h)	(h)	(h)
Total	$	47,998	6,118	5,773	5,771	30,336

(a) Includes $220 million of net unamortized premiums, discounts and debt issuance costs. See Note 11 Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

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

The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $3,412 million.

Purchase obligations of $5,169 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2019 through 2023. For additional information related to expected benefit payments subsequent to 2023, see Note 18 Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

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

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

Table of Contents

(h) Excludes unrecognized tax benefits of $966 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

Capital Expenditures

		Millions of Dollars		
		2018	2017	2016
Alaska	$	**1,298**	815	883
Lower 48		**3,184**	2,136	1,262
Canada		**477**	202	698
Europe and North Africa		**877**	872	1,020
Asia Pacific and Middle East		**718**	482	838
Other International		**6**	21	104
Corporate and Other		**190**	63	64
Capital Program	$	**6,750**	4,591	4,869

Our capital expenditures and investments for the three-year period ended December 31, 2018, totaled $16.2 billion. The 2018 expenditures supported key exploration and developments, primarily:

- Development, appraisal and exploration activities in the Lower 48, including Eagle Ford, Bakken and Delaware in the Permian Basin.
- Leasehold acquisition and exploration, appraisal and development activities in Alaska related to the Western North Slope; development activities in the Greater Kuparuk Area and the Greater Prudhoe Area.
- Development activities in Europe, including the Greater Ekofisk Area, Clair Ridge and Aasta Hansteen.
- Leasehold acquisition, optimization of oil sands development and appraisal activities in liquids-rich plays in Canada.
- Continued development in China, Australia, Indonesia, and Malaysia, and exploration and appraisal activities in Malaysia.

2019 CAPITAL BUDGET

In December 2018, we announced a 2019 capital budget of $6.1 billion which includes funding for ongoing conventional and unconventional development drilling programs, major projects, exploration and appraisal activities, and base maintenance activities. We are planning to allocate approximately:

- 70 percent of our 2019 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford, Bakken and Delaware, as well as development drilling in Alaska, Canada and Europe.
- 15 percent of our 2019 capital expenditures budget to maintain base production and corporate expenditures.

10 percent of our 2019 capital expenditures budget to major projects. These funds will focus on major projects in Alaska, China, Australia, Europe and Malaysia.
5 percent of our 2019 capital expenditures budget to new exploration activity, primarily in Alaska and the Lower 48.

Table of Contents

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the Oil and Gas Operations section.

Contingencies

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

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

Legal and Tax Matters

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

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

Environmental

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

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.

European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.

- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

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

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

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

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

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

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2018, there were 14 sites around the United States in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

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

Expensed environmental costs were $442 million in 2018 and are expected to be about $530 million per year in 2019 and 2020. Capitalized environmental costs were $191 million in 2018 and are expected to be about $240 million per year in 2019 and 2020.

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

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

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

At December 31, 2018, our balance sheet included total accrued environmental costs of $178 million, compared with $180 million at December 31, 2017, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

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

Climate Change

Continuing political and social attention to the issue of global climate change has resulted in a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction.

Table of Contents

These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2018 was approximately $5.6 million (net share before-tax).
- The Alberta Carbon Competitiveness Incentive Regulation (CCIR) requires any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or equivalent, per year to meet an industry benchmark intensity. The total cost of these regulations in 2018 was approximately $4 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirmed that the EPA has the authority to regulate carbon dioxide as an air pollutant under the Federal Clean Air Act.
- The U.S. EPA s announcement on March 29, 2010 (published as Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs, 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA s and U.S. Department of Transportation s joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- The U.S. EPA s announcement on January 14, 2015, outlining a series of steps it plans to take to address methane and smog-forming volatile organic compound emissions from the oil and gas industry. The former U.S. administration established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2018 was approximately $30 million (net share before-tax). We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia and Alberta Operations totaling just over $0.6 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework on Climate Change, setting out a new process for achieving global emission reductions. While the United States announced its intention to withdraw from the Paris Agreement, there is no guarantee that the commitments made by the United States will not be implemented, in whole or in part, by U.S. state and local governments or by major corporations headquartered in the United States.

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

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

Whether and to what extent legislation or regulation is enacted.
The timing of the introduction of such legislation or regulation.
The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation.
The price placed on GHG emissions (either by the market or through a tax).

- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

The company has responded by putting in place a Sustainable Development Risk Management Practice covering the assessment and registering of significant and high sustainable development risks based on their consequence and likelihood of occurrence. A corporate Climate Change Action Plan has been developed to track mitigation activities for each climate-related risk included in the corporate Sustainable Development Risk Register.

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

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

The company uses a range of estimated future costs of GHG emissions for internal planning purposes, including an estimated market cost of GHG emissions of $40 per metric tonne applied beginning in the year 2024 to evaluate certain future projects and opportunities. The company does not use an estimated market cost of GHG emissions when assessing reserves in jurisdictions without existing GHG regulations.

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

In 2017 and 2018, cities, counties, a state government, and a trade association in California, New York, Washington, Rhode Island and Maryland, as well as the Pacific Coast Federation of Fishermen s Association, Inc., have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. The lawsuits brought by the Cities of San Francisco, Oakland and New York have been dismissed by the district courts and appeals are pending.

Other

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

NEW ACCOUNTING STANDARDS

In February 2016, the FASB issued Accounting Standards Update (ASU) No. 2016-02, Leases (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, Leases (FASB ASC Topic 840), and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements.

ASU No. 2016-02 was amended in January 2018 by the provisions of ASU No. 2018-01, Land Easement Practical Expedient for Transition to Topic 842 (ASU No. 2018-01), and in July 2018 by the provisions of ASU No. 2018-10, Codification Improvements to Topic 842, Leases (ASU No. 2018-10). In addition, ASU No. 2016-02 was further amended in July 2018 by the provisions of ASU No. 2018-11, Targeted Improvements (ASU No. 2018-11), and in December 2018 by the provisions of ASU No. 2018-20, Narrow-Scope Improvements for Lessors (ASU No. 2018-20).

ASU No. 2018-11 sets forth certain additional practical expedients for lessors and provides entities with an option to apply the provisions of ASU No. 2016-02, as amended, to leasing arrangements existing at or entered into after the ASU s effective date of adoption (the Optional Transition Method). Entities that elect to utilize the Optional Transition Method would not apply the provisions of ASU No. 2016-02, as amended, to comparative periods presented in the financial statements.

We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, utilizing the Optional Transition Method. Accordingly, the comparative periods presented in the financial statements prior to January 1, 2019, will be presented pursuant to the existing requirements of FASB ASC Topic 840 and not be adjusted upon the adoption of the ASU. We also expect to utilize the package of optional transition-related practical expedients set forth by ASU No. 2016-02, as amended, which permit entities to not reassess upon the adoption of the ASU certain historical conclusions regarding lease contract identification and classification, as well as the historical accounting treatment of initial direct costs (the Package of Optional Practical Expedients). For lease arrangements containing both lease and non-lease components, we will adopt the optional practical expedient to not separate lease components from non-lease components for all new or modified leases executed on or after the effective date of the ASU, subject to making any elections for leases after the effective date in new asset classes. Furthermore, we do not expect to record assets and liabilities on our consolidated balance sheet for new or existing lease arrangements with terms of 12 months or less.

The expected impact of the adoption of ASU No. 2016-02, as amended, relates primarily to our balance sheet, resulting from the initial recognition of lease liabilities and corresponding right-of-use assets for our existing population of operating leases, as well as enhanced disclosure of our leasing arrangements. We expect to recognize on our consolidated balance sheet approximately $1 billion of operating lease liabilities and corresponding right-of-use assets upon the adoption of ASU No. 2016-02, as amended. We have implemented a third-party lease accounting software solution to facilitate the ongoing accounting and financial reporting requirements of the ASU and also expect the adoption of the ASU to result in certain changes being made to our existing accounting policies and systems, business processes, and internal controls.

While our evaluation of ASU No. 2016-02, as amended, and related implementation activities approach completion, we continue to monitor proposals issued by the FASB to clarify the ASU. For additional information, see Note 26 New Accounting Standards, in the Notes to Consolidated Financial Statements.

Table of Contents

CRITICAL ACCOUNTING ESTIMATES

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

Oil and Gas Accounting

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

Property Acquisition Costs

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

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2018, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $468 million and the accumulated impairment reserve was $153 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 71 percent, and the weighted-average amortization period was approximately two years. If that judgmental percentage were to be raised by 5 percent across all calculations, before-tax leasehold impairment expense in 2019 would increase by approximately $7 million. At year-end 2018, the remaining $3.6 billion of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $2.6 billion is concentrated in 10 major development areas, the majority of which are not expected to move to proved properties in 2019. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

Exploratory Costs

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

Table of Contents

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

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

At year-end 2018, total suspended well costs were $856 million, compared with $853 million at year-end 2017. For additional information on suspended wells, including an aging analysis, see Note 8 Suspended Wells and Other Exploration Expenses, in the Notes to Consolidated Financial Statements.

Proved Reserves

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

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

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

Table of Contents

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

The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2018, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $37 billion and the DD&A recorded on these assets in 2018 was approximately $5.5 billion. The estimated proved developed reserves for our consolidated operations were 3.0 billion BOE at the end of 2017 and 3.3 billion BOE at the end of 2018. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2018 would have increased by an estimated $611 million.

Impairments

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

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

Table of Contents

Asset Retirement Obligations and Environmental Costs

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

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

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

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,000 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $110 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $40 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, we could recognize a curtailment gain or loss. See Note 18 Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

Contingencies

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

Table of Contents

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

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

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

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

Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, war, terrorism, cyber attacks, and information technology failures, constraints or disruptions.

Changes in international monetary conditions and foreign currency exchange rate fluctuations.

Table of Contents

Changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil, bitumen, natural gas, LNG, natural gas liquids and any materials or products (such as aluminum and steel) used in the operation of our business.
Reduced demand for our products or the use of competing energy products, including alternative energy sources.
Substantial investment in and development of alternative energy sources, including as a result of existing or future environmental rules and regulations.
Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
Liability resulting from litigation or our failure to comply with applicable laws and regulations.
General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; the impact of and uncertainty surrounding the United Kingdom s decision to withdraw from the European Union; and other political, economic or diplomatic developments.
Volatility in the commodity futures markets.
Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business, including changes resulting from the implementation and interpretation of the Tax Cuts and Jobs Act.
Competition in the oil and gas exploration and production industry.
Any limitations on our access to capital or increase in our cost of capital, including as a result of illiquidity or uncertainty in domestic or international financial markets.
Our inability to execute, or delays in the completion, of any asset dispositions or acquisitions we elect to pursue.
Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for asset dispositions or acquisitions or that such approvals may require modification to the terms of the transactions or the operation of our remaining business.
Potential disruption of our operations as a result of asset dispositions or acquisitions, including the diversion of management time and attention.
Our inability to deploy the net proceeds from any asset dispositions we undertake in the manner and timeframe we currently anticipate, if at all.
Our inability to liquidate the common stock issued to us by Cenovus Energy as part of our sale of certain assets in western Canada at prices we deem acceptable, or at all.
The operation and financing of our joint ventures.
The ability of our customers and other contractual counterparties to satisfy their obligations to us, including our inability to collect payments when due under our ICC settlement agreement with PDVSA.
Our inability to realize anticipated cost savings and expenditure reductions.
The factors generally described in Item 1A Risk Factors in this 2018 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

Table of Contents

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

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

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

Commodity Price Risk

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

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

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2018, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2018 and 2017, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

78

Table of Contents

	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2018				
2019	**$ 17**	**- %**	**$ -**	**- %**
2020	**-**	**-**	**-**	**-**
2021	**123**	**9.13**	**-**	**-**
2022	**343**	**2.54**	**500**	**3.52**
2023	**106**	**7.20**	**-**	**-**
Remaining years	**12,599**	**6.16**	**283**	**1.78**
Total	**$ 13,188**		**$ 783**	
Fair value	**$ 15,364**		**$ 783**	
Year-End 2017				
2018	$ 2,250	3.31 %	$ 250	1.75 %
2019	23	-	-	-
2020	-	-	-	-
2021	150	9.13	-	-
2022	1,014	2.45	500	2.32
Remaining years	14,207	6.00	283	1.70
Total	$ 17,644		$ 1,033	
Fair value	$ 21,402		$ 1,033	

Foreign Currency Exchange Risk

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

At December 31, 2018 and 2017, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps and options for purposes of mitigating our cash-related exposures. Although these forwards, swaps and options hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings.

At December 31, 2018 and 2017, we had outstanding foreign currency zero-cost collars buying the right to sell $1.25 billion Canadian dollars (CAD) at $0.707 CAD and selling the right to buy $1.25 billion CAD at $0.842 CAD against the U.S. dollar. Based on the assumed volatility in the fair value calculation, the net fair value of these foreign currency contracts at December 31, 2018 and December 31, 2017, was a before-tax gain of $6 million and a before-tax loss of $9 million, respectively. Based on an adverse hypothetical 10 percent change in the December 2018 and December 2017 exchange rate, this would result in an additional before-tax loss of $17 million and $74 million respectively. The sensitivity analysis is based on changing one assumption while holding all other assumptions constant, which in practice may be unlikely to occur, as changes in some of the assumptions may be correlated.

Table of Contents

The gross notional and fair market values of these positions at December 31, 2018 and 2017, were as follows:

		In Millions			
Foreign Currency Exchange Derivatives		Notional*		Fair Market Value**	
		2018	2017	**2018**	2017
Sell U.S. dollar, buy British pound	USD	**805**	-	**(5)**	-
Sell Canadian dollar, buy U.S. dollar	CAD	**1,250**	1,250	**6**	(9)
Buy Canadian dollar, sell U.S. dollar	CAD	**8**	25	**-**	1
Sell British pound, buy Norwegian krone	GBP	**9**	-	**-**	-
Sell British pound, buy euro	GBP	**12**	1	**-**	-

**Denominated in U.S. dollars (USD), Canadian dollars (CAD) and British pound (GBP) .*

***Denominated in U.S. dollars.*

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

Table of Contents

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

Report of Management

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

Assessment of Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of the company s internal control over financial reporting as of December 31, 2018. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework (2013)*. Based on our assessment, we believe the company s internal control over financial reporting was effective as of December 31, 2018.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2018, and their report is included herein.

/s/ Ryan M. Lance

Ryan M. Lance
Chairman and

Chief Executive Officer
February 19, 2019

/s/ Don E. Wallette, Jr.

Don E. Wallette, 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 as of December 31, 2018 and 2017, and the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) (collectively referred to as the consolidated financial statements). In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of ConocoPhillips at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), ConocoPhillips internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 19, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

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

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

/s/ Ernst & Young LLP

We have served as ConocoPhillips auditor since 1949.

Houston, Texas

February 19, 2019

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

Opinion on Internal Control over Financial Reporting

We have audited ConocoPhillips internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets as of December 31, 2018 and 2017, and the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) of ConocoPhillips and our report dated February 19, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas

February 19, 2019

Table of Contents

Consolidated Income Statement **ConocoPhillips**

Years Ended December 31

	Millions of Dollars		
	2018	2017*	2016*
Revenues and Other Income			
Sales and other operating revenues	$ **36,417**	29,106	23,693
Equity in earnings of affiliates	**1,074**	772	52
Gain on dispositions	**1,063**	2,177	360
Other income	**173**	529	255
Total Revenues and Other Income	**38,727**	32,584	24,360
Costs and Expenses			
Purchased commodities	**14,294**	12,475	9,994
Production and operating expenses	**5,213**	5,162	5,643
Selling, general and administrative expenses	**401**	427	473
Exploration expenses	**369**	934	1,912
Depreciation, depletion and amortization	**5,956**	6,845	9,062
Impairments	**27**	6,601	139
Taxes other than income taxes	**1,048**	809	739
Accretion on discounted liabilities	**353**	362	425
Interest and debt expense	**735**	1,098	1,245
Foreign currency transaction (gains) losses	**(17)**	35	(19)
Other expenses	**375**	451	277
Total Costs and Expenses	**28,754**	35,199	29,890
Income (loss) before income taxes	**9,973**	(2,615)	(5,530)
Income tax provision (benefit)	**3,668**	(1,822)	(1,971)
Net income (loss)	**6,305**	(793)	(3,559)
Less: net income attributable to noncontrolling interests	**(48)**	(62)	(56)
Net Income (Loss) Attributable to ConocoPhillips	$ **6,257**	(855)	(3,615)
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*			
Basic	$ **5.36**	(0.70)	(2.91)

Diluted	**5.32**	(0.70)	(2.91)
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,166,499**	1,221,038	1,245,440
Diluted	**1,175,538**	1,221,038	1,245,440

**Certain amounts have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07. See Note 2 Changes in Accounting Principles, for additional information.*

See Notes to Consolidated Financial Statements.

85

Table of Contents

Consolidated Statement of Comprehensive Income **ConocoPhillips**
Years Ended December 31

	Millions of Dollars		
	2018	2017	2016
Net Income (Loss)	$ **6,305**	(793)	(3,559)
Other comprehensive income (loss)			
Defined benefit plans			
Prior service credit (cost) arising during the period	**(7)**	2	23
Reclassification adjustment for amortization of prior service credit included in net loss	**(40)**	(38)	(35)
Net change	**(47)**	(36)	(12)
Net actuarial gain (loss) arising during the period	**(150)**	19	(481)
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)	**279**	247	309
Net change	**129**	266	(172)
Nonsponsored plans*	**(1)**	(2)	2
Income taxes on defined benefit plans	**(42)**	(81)	78
Defined benefit plans, net of tax	**39**	147	(104)
Unrealized holding loss on securities	**-**	(58)	-
Unrealized loss on securities, net of tax**	**-**	(58)	-
Foreign currency translation adjustments	**(645)**	586	153
Reclassification adjustment for gain included in net loss	**-**	-	5
Income taxes on foreign currency translation adjustments	**3**	-	-
Foreign currency translation adjustments, net of tax	**(642)**	586	158
Other Comprehensive Income (Loss), Net of Tax	**(603)**	675	54
Comprehensive Income (Loss)	**5,702**	(118)	(3,505)
Less: comprehensive income attributable to noncontrolling interests	**(48)**	(62)	(56)

Comprehensive Income (Loss) Attributable to ConocoPhillips	$	**5,654**	(180)	(3,561)

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

*** See Note 2 Changes in Accounting Principles and Note 20 Accumulated Other Comprehensive Loss, for additional information relating to the adoption of ASU No. 2016-01.*
See Notes to Consolidated Financial Statements.

86

Table of Contents

Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2018	2017
Assets			
Cash and cash equivalents	$	**5,915**	6,325
Short-term investments		**248**	1,873
Accounts and notes receivable (net of allowance of $25 million in 2018 and $4 million in 2017)		**3,920**	4,179
Accounts and notes receivable related parties		**147**	141
Investment in Cenovus Energy		**1,462**	1,899
Inventories		**1,007**	1,060
Prepaid expenses and other current assets		**575**	1,035
Total Current Assets		**13,274**	16,512
Investments and long-term receivables		**9,329**	9,599
Loans and advances related parties		**335**	461
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $64,899 million in 2018 and $64,748 million in 2017)		**45,698**	45,683
Other assets		**1,344**	1,107
Total Assets	$	**69,980**	73,362
Liabilities			
Accounts payable	$	**3,863**	4,009
Accounts payable related parties		**32**	21
Short-term debt		**112**	2,575
Accrued income and other taxes		**1,320**	1,038
Employee benefit obligations		**809**	725
Other accruals		**1,259**	1,029
Total Current Liabilities		**7,395**	9,397
Long-term debt		**14,856**	17,128
Asset retirement obligations and accrued environmental costs		**7,688**	7,631
Deferred income taxes		**5,021**	5,282
Employee benefit obligations		**1,764**	1,854
Other liabilities and deferred credits		**1,192**	1,269
Total Liabilities		**37,916**	42,561

Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2018 1,791,637,434 shares; 2017 1,785,419,175 shares)			
Par value		**18**	18
Capital in excess of par		**46,879**	46,622
Treasury stock (at cost: 2018 653,288,213 shares; 2017 608,312,034 shares)		**(42,905)**	(39,906)
Accumulated other comprehensive loss		**(6,063)**	(5,518)
Retained earnings		**34,010**	29,391
Total Common Stockholders Equity		**31,939**	30,607
Noncontrolling interests		**125**	194
Total Equity		**32,064**	30,801
Total Liabilities and Equity	**$**	**69,980**	73,362

See Notes to Consolidated Financial Statements.

Table of Contents

Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2018	2017	2016
Cash Flows From Operating Activities			
Net income (loss)	**$ 6,305**	(793)	(3,559)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**5,956**	6,845	9,062
Impairments	**27**	6,601	139
Dry hole costs and leasehold impairments	**95**	566	1,184
Accretion on discounted liabilities	**353**	362	425
Deferred taxes	**283**	(3,681)	(2,221)
Undistributed equity earnings	**152**	(232)	299
Gain on dispositions	**(1,063)**	(2,177)	(360)
Other	**191**	(429)	(85)
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**235**	(886)	820
Decrease (increase) in inventories	**86**	(55)	44
Decrease (increase) in prepaid expenses and other current assets	**(55)**	69	105
Increase (decrease) in accounts payable	**(52)**	265	(524)
Increase (decrease) in taxes and other accruals	**421**	622	(926)
Net Cash Provided by Operating Activities	**12,934**	7,077	4,403
Cash Flows From Investing Activities			
Capital expenditures and investments	**(6,750)**	(4,591)	(4,869)
Working capital changes associated with investing activities	**(68)**	132	(331)
Proceeds from asset dispositions	**1,082**	13,860	1,286
Net sales (purchases) of short-term investments	**1,620**	(1,790)	(51)
Collection of advances/loans related parties	**119**	115	108
Other	**154**	36	(2)
Net Cash Provided by (Used in) Investing Activities	**(3,843)**	7,762	(3,859)
Cash Flows From Financing Activities			
Issuance of debt	**-**	-	4,594
Repayment of debt	**(4,995)**	(7,876)	(2,251)
Issuance of company common stock	**121**	(63)	(63)

Repurchase of company common stock	**(2,999)**	(3,000)	(126)
Dividends paid	**(1,363)**	(1,305)	(1,253)
Other	**(123)**	(112)	(137)
Net Cash Provided by (Used in) Financing Activities	**(9,359)**	(12,356)	764
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	**(117)**	232	(66)
Net Change in Cash, Cash Equivalents and Restricted Cash	**(385)**	2,715	1,242
Cash, cash equivalents and restricted cash at beginning of period	**6,536***	3,610	2,368
Cash, Cash Equivalents and Restricted Cash at End of Period	**$ 6,151**	6,325	3,610

** Restated to include $211 million of restricted cash at January 1, 2018. See Note 2 Changes in Accounting Principles for additional information relating to the adoption of ASU No. 2016-18.*

Restricted cash totaling $236 million is included in the Other assets line of our Consolidated Balance Sheet as of December 31, 2018.

See Notes to Consolidated Financial Statements.

Table of Contents

Consolidated Statement of Changes in Equity **ConocoPhillips**

	Millions of Dollars						
	Attributable to ConocoPhillips						
	Common Stock						
	Par Value	Capital in Excess of Par	Treasury Stock	Accum. Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total
December 31, 2015	$ 18	46,357	(36,780)	(6,247)	36,414	320	40,082
Net income (loss)					(3,615)	56	(3,559)
Other comprehensive income				54			54
Dividends paid ($1.00/share of common stock)					(1,253)		(1,253)
Repurchase of company common stock			(126)				(126)
Distributions to noncontrolling interests and other						(124)	(124)
Distributed under benefit plans		150					150
Other					2		2
December 31, 2016	$ 18	46,507	(36,906)	(6,193)	31,548	252	35,226
Net income (loss)					(855)	62	(793)
Other comprehensive income				675			675
Dividends paid ($1.06/share of common stock)					(1,305)		(1,305)
Repurchase of company common stock			(3,000)				(3,000)
Distributions to noncontrolling interests and other						(120)	(120)
Distributed under benefit plans		115					115
Other					3		3
December 31, 2017	$ 18	46,622	(39,906)	(5,518)	29,391	194	30,801
Net income					**6,257**	**48**	**6,305**
Other comprehensive loss				**(603)**			**(603)**
					(1,363)		**(1,363)**

Dividends paid ($1.16/share of common stock)								
Repurchase of company common stock				**(2,999)**				**(2,999)**
Distributions to noncontrolling interests and other							**(121)**	**(121)**
Distributed under benefit plans			**257**					**257**
Changes in Accounting Principles*					**58**	**(278)**		**(220)**
Other						**3**	**4**	**7**
December 31, 2018	**$**	**18**	**46,879**	**(42,905)**	**(6,063)**	**34,010**	**125**	**32,064**

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

See Notes to Consolidated Financial Statements.

Table of Contents

Notes to Consolidated Financial Statements **ConocoPhillips**

Note 1 Accounting Policies

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

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

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

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

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

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

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

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

Table of Contents

Short-Term Investments Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 2 Changes in Accounting Principles

We adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers, and its amendments issued by the provisions of ASU No. 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), ASU No. 2016-10, Identifying Performance Obligations and Licensing, ASU No. 2016-12, Narrow-Scope Improvements and Practical Expedients, and ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue From Contracts with Customers, collectively Accounting Standards Codification (ASC) Topic 606, Revenue from Contracts with Customers, (ASC Topic 606) beginning January 1, 2018. ASC Topic 606 outlines a single comprehensive model for an entity to use in accounting for revenue arising from all contracts with customers except where revenues are in scope of another accounting standard. The ASU superseded the revenue recognition requirements in ASC Topic 605, Revenue Recognition, and most industry-specific guidance. ASC Topic 606 sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity is required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods and services. ASC Topic 606 also requires certain additional revenue-related disclosures. The adoption of ASC Topic 606 did not have a material impact on our consolidated financial statements. See Note 24 Sales and Other Operating Revenues for additional information related to this ASC.

We adopted the provisions of FASB ASU No. 2016-01, Recognition and Measurement of Financial Assets and Liabilities, (ASU No. 2016-01) beginning January 1, 2018. The ASU, among other things, requires an entity to record the changes in fair value of equity investments, other than investments accounted for using the equity method, within net income. Under this ASU, an entity is no longer able to recognize unrealized holding gains and losses on equity securities in other comprehensive income and instead must recognize them in the income statement. See Note 7 Investment in Cenovus Energy and Note 20 Accumulated Other Comprehensive Loss for additional information relating to this ASU.

Table of Contents

The cumulative effect of the changes made to our consolidated balance sheet at January 1, 2018, for the adoption of ASC Topic 606 and ASU No. 2016-01 were as follows:

	Millions of Dollars			
	December 31 2017	ASC Topic 606 Adjustments	ASU No. 2016-01 Adjustments	**January 1 2018**
Liabilities				
Other accruals	$ 1,029	104	-	**1,133**
Total current liabilities	9,397	104	-	**9,501**
Deferred income taxes	5,282	(31)	-	**5,251**
Other liabilities and deferred credits	1,269	147	-	**1,416**
Total liabilities	42,561	220	-	**42,781**
Equity				
Accumulated other comprehensive loss	$ (5,518)	-	58	**(5,460)**
Retained earnings	29,391	(220)	(58)	**29,113**
Total common stockholders equity	30,607	(220)	-	**30,387**
Total equity	30,801	(220)	-	**30,581**

For discussion of adjustments for ASU No. 2016-01 and ASC Topic 606, see Note 7 Investment in Cenovus Energy and Note 24 Sales and Other Operating Revenues, respectively.

We adopted the provisions of FASB ASU No. 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, beginning January 1, 2018. We retrospectively applied the presentation of service cost separate from the other components of net periodic costs. The interest cost, expected return on plan assets, amortization of prior service cost/credit, recognized net actuarial loss/gain, settlement expense, curtailment loss/gain, and special termination benefits have been reclassified from the Production and operating expenses, Selling, general and administrative expenses, and Exploration expenses lines to the Other expenses line on our consolidated income statement. We elected to apply the practical expedient which allows us to reclassify amounts disclosed previously in the employee benefit plans footnote as the basis for applying retrospective presentation for prior comparative periods as it is impracticable to determine the disaggregation of the cost components for amounts capitalized and amortized in those periods. On a prospective basis, the other components of net periodic benefit costs will not be included in amounts capitalized in inventory or PP&E.

The effect of the retrospective presentation change related to the net periodic benefit cost of our defined benefit pension and other postretirement employee benefits plans on our consolidated income statement was as follows:

	Millions of Dollars		
	Previously Reported	Effect of Change Higher/(Lower)	As Revised
Year Ended December 31, 2017			

Production and operating expenses	$ 5,173	(11)	5,162
Selling, general and administrative expenses	561	(134)	427
Exploration expenses	938	(4)	934
Other expenses	302	149	451
Year Ended December 31, 2016			
Production and operating expenses	$ 5,667	(24)	5,643
Selling, general and administrative expenses	723	(250)	473
Exploration expenses	1,915	(3)	1,912
Other expenses	-	277	277

Table of Contents

We adopted the provisions of FASB ASU No. 2016-15, Classification of Certain Cash Receipts and Cash Payments, beginning January 1, 2018. This ASU clarifies how certain cash receipts and cash payments should be classified and presented in the statement of cash flows. We have made an accounting policy election to classify distributions received from equity method investees using the nature of the distribution approach which classifies distributions received from investees as either cash inflows from operating activities or cash inflows from investing activities in the statement of cash flows based on the nature of the activities of the investee that generated the distribution. The impact of adopting this ASU was not material to prior presented periods.

We adopted the provisions of FASB ASU No. 2016-18, Restricted Cash, beginning January 1, 2018. This ASU requires amounts deemed restricted cash to be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, and presentation should permit a reconciliation when cash, cash equivalents and restricted cash are presented in more than one line item on the balance sheet. We have amounts deposited in statutory bank accounts in certain countries to satisfy asset retirement obligations (ARO). These amounts are deemed restricted cash and are included in the Other assets line of our consolidated balance sheet. This standard is required to be applied retrospectively to all periods presented, but the impact in those periods was not material.

Note 3 Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

Australia Pacific LNG Pty Ltd (APLNG)

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2018, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 6 Investments, Loans and Long-Term Receivables, and Note 12 Guarantees, for additional information.

Marine Well Containment Company, LLC (MWCC)

MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. We have a 10 percent ownership interest in MWCC, and it is accounted for as an equity method investment because MWCC is a limited liability company in which we are a Founding Member and exercise significant influence through our permanent seat on the ten-member Executive Committee responsible for overseeing the affairs of MWCC. In 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. MWCC is considered a VIE, as it has entered into arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary and do not consolidate MWCC because we share the power to govern the business and operation of the company and to undertake certain obligations that most significantly impact its economic performance with nine other unaffiliated owners of MWCC.

At December 31, 2018, the book value of our equity method investment in MWCC was $130 million. We have not provided any financial support to MWCC other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of MWCC.

Note 4 Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2018	2017
Crude oil and natural gas	$	**432**	512
Materials and supplies		**575**	548
	$	**1,007**	1,060

Inventories valued on the LIFO basis totaled $292 million and $341 million at December 31, 2018 and 2017, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $75 million and $124 million at December 31, 2018 and December 31, 2017, respectively. In 2018, liquidation of LIFO inventory values decreased the net income attributable to ConocoPhillips by $6 million.

Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions

Assets Held for Sale

In 2018, we signed a definitive agreement to sell an office building for $90 million, and the held for sale criteria were met in the fourth quarter of 2018. As of December 31, 2018, the building had a carrying value of $90 million which we reclassified to Prepaid expenses and other current assets on our consolidated balance sheet. The transaction closed in January 2019. The building is included in our Corporate and other segment.

2018

Assets Sold

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

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

On October 31, 2018, we completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments and recognized a loss of $5 million. We recorded impairments of $87 million in 2018 and $572 million in 2017 to reduce the net carrying value of the Barnett to fair value. At the time of the disposition, our interest in Barnett had a net carrying value of $201 million, consisting of $250 million of PP&E and $49 million of AROs. The before-tax losses associated with our interests in the Barnett, including both the impairments and loss on disposition noted above, were $59 million, $566 million and $66 million for the years ended December 31, 2018, 2017 and 2016, respectively. The Barnett results of operations are included in our Lower 48 segment.

On December 18, 2018, we completed the sale of a ConocoPhillips subsidiary to BP. The subsidiary held a 16.5 percent interest in the BP-operated Clair Field in the United Kingdom. We retained a 7.5 percent interest in the field. At the same time, we acquired BP s 39.2 percent nonoperated interest in the Greater Kuparuk Area in Alaska, including their 38 percent interest in the Kuparuk Transportation Company (Kuparuk Assets). The transaction was recorded at a fair value of $1,743 million and was cash neutral except for customary adjustments which resulted in net proceeds of $253 million. At closing, our 16.5 percent interest in the Clair Field had a net carrying value of approximately $1,028 million consisting primarily of $1,553 million of PP&E, $485 million of deferred tax liabilities, and $59 million of AROs. We recognized a before-tax gain of $715 million on the transaction. The 2018 before-tax earnings associated with our 16.5 percent interest in the Clair Field, including the recognized gain, were $748 million. The before-tax losses associated with our 16.5 percent interest in the Clair Field were $0.4 million and $8 million for the years ended December 31, 2017 and 2016, respectively. Results of operations for our interest in the Clair Field are reported within our Europe and North Africa segment and the Kuparuk Assets are included in our Alaska segment.

Other Planned Dispositions

In the fourth quarter of 2018, we entered into an agreement to sell our 30 percent interest in Greater Sunrise Fields to the government of Timor-Leste for $350 million, subject to customary adjustments. The transaction is conditional on the funding approval from the Timor-Leste government as well as regulatory approvals. The Greater Sunrise Fields are included in our Asia Pacific and Middle East segment.

In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in the Golden Pass LNG Terminal and Golden Pass Pipeline located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal and pipeline capacity are used for receipt, storage and regasification of LNG purchased from Qatar Liquefied Gas Company Limited (QG3) and transportation of the regasified natural gas. As a result of entering into these agreements, we expect to recognize a loss of approximately $60 million in the first quarter of 2019. We have also entered into agreements to amend our contractual obligations for retaining use of the facilities. Completion of the sale is subject to regulatory approval.

Acquisitions

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

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

2017

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11.0 billion in cash after customary adjustments, 208 million Cenovus Energy common shares and a five-year uncapped contingent payment. The value of the shares at closing was

$1.96 billion based on a price of $9.41 per share on the New York Stock Exchange. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel. Contingent payments received during the five-year period are reflected as Gain on dispositions on our consolidated income statement. We reported before-tax equity earnings associated with FCCL of $197 million and $89 million for the years ended December 31, 2017 and 2016, respectively. We reported before-tax losses of $26 million and $572 million for the western Canada gas producing properties for the same periods, respectively. In 2018, we recorded a gain on dispositions for these contingent payments of $95 million.

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

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

In July 2017, we completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company for $2.5 billion in cash after customary adjustments and recognized a loss on disposition of $22 million. The transaction includes a contingent payment of up to $300 million. The six-year contingent payment, effective beginning January 1, 2018, is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units. In 2018, we recorded a gain on dispositions for these contingent payments of $28 million. In the second quarter of 2017, we recorded an impairment of $3.3 billion to reduce the carrying value of our interests in the San Juan Basin to fair value. At the time of disposition, the San Juan Basin interests had a net carrying value of approximately $2.5 billion, consisting of $2.9 billion of PP&E and $406 million of liabilities, primarily AROs. The before-tax losses associated with our interests in the San Juan Basin, including both the $3.3 billion impairment and $22 million loss on disposition noted above, were $3.2 billion and $239 million for the years ended December 31, 2017 and 2016, respectively. The San Juan Basin results were reported in our Lower 48 segment.

In September 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments, and recognized a loss on disposition of $28 million. At the time of the disposition, the carrying value of our interest was $206 million, consisting primarily of $279 million of PP&E and $72 million of AROs. Including the $28 million loss on disposition noted above, we reported before-tax losses for the Panhandle properties of $14 million and $21 million for the years ended December 31, 2017 and 2016, respectively. The Panhandle results were reported in our Lower 48 segment.

2016

In April 2016, we sold our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet for $134 million, net of settlement of gas imbalances and customary adjustments, and recognized a gain on disposition of $56 million. At the time of disposition, the net carrying value of our Beluga River Unit interest, which was included in the Alaska segment, was $78 million, consisting primarily of $100 million of PP&E and $19 million of AROs.

In October 2016, we completed an asset exchange with Bonavista Energy in which we gave up approximately 141,000 net acres of noncore developed properties in central Alberta in exchange for approximately 40,000 net acres of primarily undeveloped properties in northeast British Columbia. The fair value of the transaction was determined to be approximately $69 million and an impairment of $57 million was recognized in the third quarter of 2016 when the assets were considered held for sale, to reduce the carrying value to fair value. A loss on disposition of approximately $1 million was recognized upon completion of the transaction. The divested properties were included in the Canada segment.

Table of Contents

Also in October 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal for $442 million and recognized a gain on disposition of $146 million. At the time of disposition, the carrying value of our interest was $286 million, which was primarily PP&E. Senegal results of operations were reported within our Other International segment.

In November 2016, we completed the sale of our 40 percent interest in South Natuna Sea Block B for $225 million and recognized a loss on disposition of $26 million. Our interest in Block B was included in the Asia Pacific and Middle East segment. In 2016, we recognized an impairment of $42 million at the time it was considered held for sale to reduce the carrying value to fair value. At the time of the disposition, the carrying value of our interest was approximately $251 million, which included primarily $154 million of PP&E, $178 million of accounts receivable, $25 million of inventory, $54 million of deferred tax assets, $130 million of accounts payable and other accruals, and $38 million of employee benefit obligations.

In December 2016, we completed the sale of certain mineral and non-mineral fee lands in northeastern Minnesota, which were included in the Lower 48 segment, for $148 million and recorded a gain on disposition of $4 million. The majority of the assets sold were acquired during the fourth quarter of 2016 as a result of ConocoPhillips holding a reversionary interest in the Greater Northern Iron Ore Properties Trust (the Trust), a grantor trust that owned mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. In November 2016, upon completion of the wind-down period, documents memorializing ConocoPhillips ownership of certain Trust property, including all of the Trust s mineral properties and active leases, were delivered to us and we recognized the fair value of the net assets resulting in a gain of $88 million recorded in the Other income line on our consolidated income statement. At the time of the disposition, the carrying value of our interests, which included the assets obtained from the Trust, consisted of $144 million of PP&E.

Note 6 Investments, Loans and Long-Term Receivables

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

		Millions of Dollars	
		2018	2017
Equity investments	$	**9,005**	9,129
Loans and advances related parties		**335**	461
Long-term receivables		**238**	375
Other investments		**86**	95
	$	**9,664**	10,060

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2018, included:

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

Table of Contents

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

	Millions of Dollars		
	2018	2017	2016
Revenues	$ **11,654**	11,554	10,149
Income (loss) before income taxes	**3,660**	(2,875)	660
Net income (loss)	**3,244**	(1,431)	799

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

	Millions of Dollars	
	2018	2017
Current assets	$ **3,285**	2,920
Noncurrent assets	**41,563**	42,693
Current liabilities	**2,625**	2,453
Noncurrent liabilities	**23,874**	25,522

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

At December 31, 2018, retained earnings included $27 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,226 million, $605 million and $398 million in 2018, 2017 and 2016, respectively.

APLNG

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

APLNG executed project financing agreements for an $8.5 billion project finance facility in 2012. The $8.5 billion project finance facility was initially composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately

$2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. At December 31, 2018, all amounts have been drawn from the facility. APLNG made its first principal and interest repayment in March 2017 and is scheduled to make bi-annual payments until March 2029.

APLNG made a voluntary repayment of $1.4 billion to the Export-Import Bank of China in September 2018. At the same time, APLNG obtained a United States Private Placement (USPP) bond facility of $1.4 billion. Interest payments are scheduled to commence in March 2019 and principal payments in September 2023, with bi-annual payments due on the facility until September 2030. At December 31, 2018, a balance of $7.2 billion was outstanding on the facilities.

In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for both trains, which removed the remaining guarantee.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 3 Variable Interest Entities (VIEs) for additional information.

On July 1, 2016, APLNG changed its tax functional currency from Australian dollar to U.S. dollar and translated all APLNG assets and liabilities into U.S. dollar, utilizing the exchange rate as of that date. As a result of this change, we recorded a reduction to our investment in APLNG for the deferred tax effect of $174 million in the Equity in earnings of affiliates line of our consolidated income statement.

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

At December 31, 2018, the carrying value of our equity method investment in APLNG was $7,522 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $7,231 million, resulting in a basis difference of $291 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income (loss) attributable to ConocoPhillips for 2018, 2017 and 2016 was after-tax expense of $44 million, $100 million and $92 million, respectively, representing the amortization of this basis difference on currently producing licenses.

Distributions from APLNG commenced in April 2018.

FCCL

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

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

Table of Contents

QG3

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $461 million as described below under Loans and Long-Term Receivables. At December 31, 2018, the book value of our equity method investment in QG3, excluding the project financing, was $921 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States. In January 2019, we entered into agreements to sell our ownership interests in Golden Pass LNG Terminal and Golden Pass Pipeline. For additional information, see Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions.

Loans and Long-Term Receivables

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

At December 31, 2018, significant loans to affiliated companies include $461 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

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

Note 7 Investment in Cenovus Energy

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets, to Cenovus Energy. Consideration for the transaction included 208 million Cenovus Energy common shares, which approximated 16.9 percent of issued and outstanding Cenovus Energy common stock at closing. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions for additional information on the Canada disposition. At closing of the sale, the fair value and cost basis of our investment in 208 million Cenovus Energy common shares was $1.96 billion based on a price of $9.41 per share on the New York Stock Exchange.

We adopted the provisions of ASU No. 2016-01, beginning January 1, 2018, using the cumulative-effect approach. Results for reporting periods beginning January 1, 2018, are presented under ASU No. 2016-01 with all changes in the fair value of our equity securities reflected within the Other income line of our consolidated income statement and within the Other line in the Cash Flows From Operating Activities section of our consolidated statement of cash flows.

Prior period amounts are not adjusted under the cumulative-effect method of adopting ASU No. 2016-01. See Note 2 Changes in Accounting Principles and Note 20 Accumulated Other Comprehensive Loss for the effect on our consolidated balance sheet and the line items that have been impacted by the adoption of this standard.

Table of Contents

The cumulative effect of applying the standard was the reclassification of accumulated unrealized holding losses of $58 million, recognized in 2017, related to our investment in Cenovus Energy from accumulated other comprehensive loss to retained earnings.

Our investment is carried at fair value of $1.46 billion as of December 31, 2018, reflecting the closing price of Cenovus Energy shares on the New York Stock Exchange of $7.03 per share, a decrease from its fair value of $1.90 billion at year-end 2017. For the year ended December 31, 2018, we recorded a before-tax unrealized loss of $437 million, related to the shares held at the reporting date. See Note 15 Fair Value Measurement, for additional information. Subject to market conditions, we intend to decrease our investment over time through market transactions, private agreements or otherwise.

Note 8 Suspended Wells and Other Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2018, 2017 and 2016:

		Millions of Dollars		
		2018	2017	2016
Beginning balance at January 1	$	**853**	1,063	1,260
Additions pending the determination of proved reserves		**140**	118	225
Reclassifications to proved properties		**(37)**	(66)	(27)
Sales of suspended wells		**(93)**	-	(247)
Charged to dry hole expense		**(7)**	(262)	(148)
Ending balance at December 31	$	**856**	853	1,063

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

		Millions of Dollars		
		2018	2017	2016
Exploratory well costs capitalized for a period of one year or less	$	**145**	67	132
Exploratory well costs capitalized for a period greater than one year		**711**	786	931
Ending balance	$	**856**	853	1,063
Number of projects with exploratory well costs capitalized for a period greater than one year		**24**	23	26

Table of Contents

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2018:

		Millions of Dollars						
					Suspended Since			
		Total	2015	2017	2012	2014	2004	2011
Greater Poseidon Australia[2]		177		-		165		12
Barossa/Caldita Australia[2]		136		59		-		77
Surmont Canada[1]		108		18		56		34
NPRA Alaska[1]		77		39		38		-
Middle Magdalena Basin Colombia[1]		65		65		-		-
Greater Clair UK[2]		42		8		30		4
Bohai China[2]		19		19		-		-
Kamunsu East Malaysia[2]		19		-		19		-
NC 98 Libya[2]		15		-		11		4
Sunrise Australia[2]		13		-		-		13
Other of $10 million or less each[1][2]		40		5		18		17
Total	$	711		213		337		161

(1)Additional appraisal wells planned.

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

In July 2016, we entered into an agreement to terminate our final Gulf of Mexico deepwater drillship contract. The drillship, used to drill our operated deepwater well inventory in the Gulf of Mexico through April 2016, was contracted on a shared, three-year term. Accordingly, we recorded before-tax rig cancellation charges and third-party costs of $146 million in our Lower 48 segment in 2016.

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

Note 9 Impairments

During 2018, 2017 and 2016, we recognized the following before-tax impairment charges:

Millions of Dollars

	2018	2017	2016
Alaska	**$ 20**	180	1
Lower 48	**63**	3,969	149
Canada	**9**	22	88
Europe and North Africa	**(79)**	46	(160)
Asia Pacific and Middle East	**14**	2,384	44
Corporate	**-**	-	17
	$ 27	6,601	139

2018

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

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

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

2017

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

In the Lower 48, we recorded impairments of $3,969 million primarily due to certain developed properties which were written down to fair value less costs to sell. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions, for additional information on our dispositions.

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

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

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

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

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

2016

In the Lower 48, we recorded impairments of $149 million primarily due to cancelled projects associated with plan of development changes for Eagle Ford infrastructure, as well as lower natural gas prices and increased ARO estimates.

In Canada, we recorded impairments of $88 million mainly due to plan of development changes, as well as certain developed properties being written down to fair value less costs to sell.

In Europe and North Africa, we recorded a credit to impairment of $160 million, primarily in the United Kingdom, due to decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years, partly offset by asset impairments due to lower natural gas prices in the United Kingdom.

In Asia Pacific and Middle East, we recorded impairments of $44 million, mainly due to a write-down to fair value less costs to sell of our developed properties in Block B, offshore Indonesia, in the third quarter of 2016.

In Corporate and Other, we recorded impairments of $17 million due to cancelled projects in our Houston and Bartlesville offices.

Table of Contents

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

Charges recorded in exploration expenses in 2016 were related to our decision announced in 2015 to reduce deepwater exploration spending.

In our Lower 48 segment, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. Additionally, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect and a $79 million before-tax impairment, primarily as a result of changes in the estimated market value following the completion of marketing efforts.

In our Canada segment, we recorded before-tax unproved property impairments of $31 million, primarily due to decisions to discontinue additional testing of undeveloped leaseholds.

Note 10 Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2018	2017
Asset retirement obligations	**$ 7,908**	7,798
Accrued environmental costs	**178**	180
Total asset retirement obligations and accrued environmental costs	**8,086**	7,978
Asset retirement obligations and accrued environmental costs due within one year*	**(398)**	(347)
Long-term asset retirement obligations and accrued environmental costs	**$ 7,688**	7,631

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

Asset Retirement Obligations

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

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

Table of Contents

During 2018 and 2017, our overall ARO changed as follows:

	Millions of Dollars	
	2018	2017
Balance at January 1	**$ 7,798**	8,405
Accretion of discount	**348**	358
New obligations	**657**	113
Changes in estimates of existing obligations	**(266)**	(150)
Spending on existing obligations	**(228)**	(152)
Property dispositions	**(161)**	(1,065)
Foreign currency translation	**(240)**	289
Balance at December 31	**$ 7,908**	7,798

Accrued Environmental Costs

Total accrued environmental costs at December 31, 2018 and 2017, were $178 million and $180 million, respectively.

We had accrued environmental costs of $100 million and $105 million at December 31, 2018 and 2017, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $67 million and $60 million of environmental costs associated with sites no longer in operation at December 31, 2018 and 2017, respectively. In addition, $11 million and $15 million were included at both December 31, 2018 and 2017, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $88 million at December 31, 2018. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $6 million in 2019, $6 million in 2020, $10 million in 2021, $6 million in 2022, $2 million in 2023, and $109 million for all future years after 2023.

Table of Contents

Note 11 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2018	2017
9.125% Debentures due 2021	$ **123**	150
8.20% Debentures due 2025	**134**	150
8.125% Notes due 2030	**390**	600
7.9% Debentures due 2047	**60**	100
7.8% Debentures due 2027	**203**	300
7.65% Debentures due 2023	**78**	88
7.40% Notes due 2031	**500**	500
7.375% Debentures due 2029	**92**	92
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.50% Notes due 2039	**2,750**	2,750
5.951% Notes due 2037	**645**	645
5.95% Notes due 2036	**500**	500
5.95% Notes due 2046	**500**	500
5.90% Notes due 2032	**505**	505
5.90% Notes due 2038	**600**	600
4.95% Notes due 2026	**1,250**	1,250
4.30% Notes due 2044	**750**	750
4.20% Notes due 2021	**-**	1,000
4.15% Notes due 2034	**246**	500
3.35% Notes due 2024	**426**	1,000
3.35% Notes due 2025	**199**	500
2.875% Notes due 2021	**-**	750
2.4% Notes due 2022	**329**	1,000
2.2% Notes due 2020	**-**	500
Floating rate notes due 2018 at 1.24% 1.75% during 2017	**-**	250
Floating rate notes due 2022 at 2.32% 3.52% during 2018 and 1.81% 2.32% during 2017	**500**	500
Industrial Development Bonds due 2018 through 2038 at 0.95% 1.86% during 2018 and 0.64% 1.74% during 2017	**18**	18
Marine Terminal Revenue Refunding Bonds due 2031 at 0.88% 1.95% during 2018 and 0.64% 1.74% during 2017	**265**	265
Other	**17**	23
Debt at face value	**13,971**	18,677
Capitalized leases	**777**	774

Net unamortized premiums, discounts and debt issuance costs	**220**	252
Total debt	**14,968**	19,703
Short-term debt	**(112)**	(2,575)
Long-term debt	**$ 14,856**	17,128

109

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2019 through 2023 are: $112 million, $101 million, $213 million, $935 million and $195 million, respectively.

In May 2018, we refinanced our revolving credit facility from a total aggregate principal amount of $6.75 billion to $6.0 billion with a new expiration date of May 2023. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper program. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

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

The revolving credit facility supports the ConocoPhillips Company $6.0 billion commercial paper program, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding in programs in place at December 31, 2018 or December 31, 2017. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at December 31, 2018 or December 31, 2017. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.0 billion in borrowing capacity under our revolving credit facility at December 31, 2018.

In 2018, we repaid the $250 million floating rate note due in 2018 at its natural maturity.

We also redeemed or repurchased a total $4,450 million of debt in 2018, described below, incurring $208 million in net premiums above book value, which are reported in the Other expenses line on our consolidated income statement.

- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.
- 2.4% Notes due 2022 with principal of $1.0 billion (partial repurchase of $671 million).
- 3.35% Notes due 2024 with principal of $1.0 billion (partial repurchase of $574 million).
- 2.2% Notes due 2020 with principal of $500 million.
- 3.35% Notes due 2025 with principal of $500 million (partial repurchase of $301 million).
- 4.15% Notes due 2034 with principal of $500 million (partial repurchase of $254 million).
- 8.125% Notes due 2030 with principal of $600 million (partial repurchase of $210 million).
- 7.8% Notes due 2027 with principal of $300 million (partial repurchase of $97 million).
- 7.9% Notes due 2047 with principal of $100 million (partial repurchase of $40 million).
- 9.125% Notes due 2021 with principal of $150 million (partial repurchase of $27 million).
- 8.20% Notes due 2025 with principal of $150 million (partial repurchase of $16 million).
- 7.65% Notes due 2023 with principal of $88 million (partial repurchase of $10 million).

At both December 31, 2018 and 2017, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the Long-term debt line on our consolidated balance sheet.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our before-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Our proportionate interest in the FPS is 29 percent as of December 31, 2018. The net carrying value of the capital lease asset was approximately $353 million and $434 million as of December 31, 2018 and 2017, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the Depreciation, depletion and amortization line on our consolidated income statement. As of December 31, 2018 and 2017, accumulated depreciation of the capital lease asset amounted to approximately $462 million and $381 million, respectively.

At December 31, 2018, future minimum payments due under capital leases were:

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

Note 12 Guarantees

At December 31, 2018, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

APLNG Guarantees

At December 31, 2018, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2018 exchange rates:

During the third quarter of 2016, we issued a guarantee to facilitate the withdrawal of our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee is 12 years. Our maximum exposure under this guarantee is approximately $170 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2018, the carrying value of this guarantee is approximately $14 million.

In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of up to 23 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $800 million ($1.4 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project s continued development. The guarantees have remaining terms of up to 27 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $140 million and would become payable if APLNG does not perform.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $780 million, which consist primarily of guarantees of the residual value of leased office buildings, guarantees of the residual value of leased corporate aircraft, and a guarantee for our portion of a joint venture s project finance reserve accounts. These guarantees have remaining terms of up to four years and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

Indemnifications

Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2018, was approximately $90 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at December 31, 2018, were approximately $30 million of environmental accruals for known contamination that are included in the Asset retirement obligations and accrued environmental costs line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 13 Contingencies and Commitments.

In 2012, we completed the separation of our downstream business, creating two independent energy companies: ConocoPhillips and Phillips 66. On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream businesses formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. As of December 31, 2017, the carrying value of this guarantee was $98 million. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we also recorded an indemnification asset from Phillips 66 of $98 million. During the third quarter of 2018, a termination agreement between the supplier and Phillips 66 was executed, releasing all parties from their respective obligations under the supply agreement. Since all obligations under the supply agreement were satisfied and discharged, the guarantee was terminated. As of December 31, 2018, the carrying value of this guarantee and the associated indemnification asset have been removed.

Table of Contents

Note 13 Contingencies and Commitments

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

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

Environmental

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

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

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

Legal Proceedings

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

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

Other Contingencies

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2018, we had performance obligations secured by letters of credit of $323 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, ConocoPhillips was unable to reach agreement with respect to the *empresa mixta* structure mandated by the Venezuelan government s Nationalization Decree. As a result, Venezuela s national oil company, Petróleos de Venezuela, S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, ConocoPhillips initiated international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela s actions.

In 2014, ConocoPhillips filed a separate and independent arbitration under the rules of the International Chamber of Commerce (ICC) against PDVSA under the contracts that had established the Petrozuata and Hamaca projects. The ICC Tribunal issued an award in April 2018, finding that PDVSA owed ConocoPhillips approximately $2 billion under their agreements in connection with the expropriation of the projects and other pre-expropriation fiscal measures. In August 2018, ConocoPhillips entered into a settlement with PDVSA to recover the full amount of this ICC award, plus interest through the payment period, including initial payments totaling approximately $500 million within a period of 90 days from the time of signing of the settlement agreement. The balance of the settlement is to be paid quarterly over a period of four and a half years. By year-end 2018, we collected from PDVSA under the settlement and recognized in other income $430 million before-tax consisting of $230 million from the sale of commodity inventory and $200 million in cash. The remainder of the initial payments will become an adjustment to a future quarterly installment. Per the settlement, PDVSA recognized the ICC award as a judgment in various jurisdictions, and ConocoPhillips agreed to suspend its legal enforcement actions, including in the Dutch Caribbean. ConocoPhillips has ensured that the settlement meets all appropriate U.S. regulatory requirements, including any applicable sanctions imposed by the U.S. against Venezuela.

Table of Contents

In 2016, ConocoPhillips filed a separate and independent arbitration under the rules of the ICC against PDVSA under the contracts that had established the Corocoro project. This ICC arbitration is currently in progress.

In February 2017, the ICSID tribunal unanimously awarded Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, $380 million for Ecuador s unlawful expropriation of Burlington s investment in Blocks 7 and 21, in breach of the U.S.-Ecuador Bilateral Investment Treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for environmental and infrastructure counterclaims. In December 2017, Burlington and Ecuador entered into a settlement agreement by which Ecuador paid Burlington $337 million in two installments. The first installment of $75 million was paid in December 2017, and the second installment of $262 million was paid in April 2018. The settlement included an offset for the counterclaims decision, of which Burlington is entitled to a $24 million contribution from Perenco Ecuador Limited, its co-venturer and consortium operator, pursuant to a joint and several liability provision in the joint operating agreement (JOA). Ecuador s environmental and infrastructure counterclaims against Perenco remain pending in a separate ICSID arbitration between Perenco and Ecuador, and Burlington may owe Perenco contribution under the JOA for damages found by this tribunal.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. In 2018, the parties reached a confidential settlement.

In June 2017, FAR Ltd. initiated arbitration before the ICC against ConocoPhillips Senegal B.V. in connection with the sale of ConocoPhillips Senegal B.V. to Woodside Energy Holdings (Senegal) Limited in 2016. This arbitration is ongoing.

In late 2017, ConocoPhillips (U.K.) Limited (CPUKL) initiated United Nations Commission on International Trade and Law (UNCITRAL) arbitration against Vietnam in accordance with the U.K.-Vietnam Bilateral Investment Treaty relating to a tax dispute arising from the 2012 sale of ConocoPhillips (U.K.) Cuu Long Limited and ConocoPhillips (U.K.) Gama Limited. The tribunal was constituted in February 2018. The arbitration is ongoing.

In 2017 and 2018, cities, counties, a state government, and a trade association in California, New York, Washington, Rhode Island and Maryland, as well as the Pacific Coast Federation of Fishermen s Association, Inc., have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. The lawsuits brought by the Cities of San Francisco, Oakland and New York have been dismissed by the district courts and appeals are pending.

Several Louisiana parishes and individual landowners have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages in connection with historical oil and gas operations in Louisiana. ConocoPhillips will vigorously defend against these lawsuits.

Long-Term Throughput Agreements and Take-or-Pay Agreements

We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company s business. The aggregate amounts of estimated payments under these various agreements are: 2019 $7 million; 2020 $7 million; 2021 $7 million; 2022 $7 million; 2023 $7 million; and 2024 and after $61 million. Total payments under the agreements were $39 million in 2018, $43 million in 2017 and $42 million in 2016.

115

Table of Contents

Note 14 Derivative and Financial Instruments

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

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

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

		Millions of Dollars	
		2018	2017
Assets			
Prepaid expenses and other current assets	$	**410**	275
Other assets		**40**	36
Liabilities			
Other accruals		**370**	282
Other liabilities and deferred credits		**30**	28

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

		Millions of Dollars		
		2018	2017	2016
Sales and other operating revenues	$	**45**	77	(198)
Other income		**7**	-	(1)
Purchased commodities		**(41)**	(61)	161

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

	Open Position Long/(Short)	
	2018	2017
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(17)**	(29)
Basis	**(1)**	12

116

Table of Contents

Foreign Currency Exchange Derivatives

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

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

		Millions of Dollars	
		2018	2017
Assets			
Prepaid expenses and other current assets	**$**	**7**	1
Other assets		-	6
Liabilities			
Other accruals		**6**	-
Other liabilities and deferred credits		**-**	15

In December 2017, we entered into foreign exchange zero cost collars buying the right to sell $1.25 billion CAD at $0.707 CAD and selling the right to buy $1.25 billion CAD at $0.842 CAD against the U.S. dollar.

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

		Millions of Dollars		
		2018	2017	2016
Foreign currency transaction losses	**$**	**1**	13	247

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

	In Millions	
	Notional Currency	
	2018	2017

Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy British pound	USD	**805**	-
Sell British pound, buy other currencies*	GBP	**21**	1
Sell Canadian dollar, buy U.S. dollar	CAD	**1,242**	1,225

**Primarily euro and Norwegian krone.*

Financial Instruments

We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments that we currently invest include:

Time deposits: Interest bearing deposits placed with approved financial institutions.
Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.
Government or government agency obligations: Short-term securities issued by the U.S. government or U.S. government agencies.

These financial instruments appear in the "Cash and cash equivalents" line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these financial instruments are included in the "Short-term investments" line on our consolidated balance sheet.

		Millions of Dollars			
		Carrying Amount			
		Cash and Cash Equivalents		Short-Term Investments	
		2018	2017	**2018**	2017
Cash	$	**876**	948		
Time Deposits					
Remaining maturities from 1 to 90 days		**3,509**	5,004	**-**	821
Commercial Paper					
Remaining maturities from 1 to 90 days		**229**	373	**248**	978
Remaining maturities from 91 to 180 days		**-**	-	**-**	74
Government Obligations					
Remaining maturities from 1 to 90 days		**1,301**	-	**-**	-
	$	**5,915**	6,325	**248**	1,873

Credit Risk

Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (OTC) derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, government money market funds, government debt securities and time deposits with major international banks and financial institutions.

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

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

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

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2018 and December 31, 2017, was $62 million and $55 million, respectively. For these instruments, no collateral was posted as of December 31, 2018 or December 31, 2017. If our credit rating had been downgraded below investment grade on December 31, 2018, we would be required to post $62 million of additional collateral, either with cash or letters of credit.

Note 15 Fair Value Measurement

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

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

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. At the end of the fourth quarter of 2017, our $1,899 million investment in Cenovus Energy was transferred from Level 2 to Level 1 due to the lapsing of trading restrictions. There were no other material transfers in or out of Level 1 during 2018 or 2017.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include our investment in Cenovus Energy shares and commodity derivatives. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 1 also includes our investment in common shares of Cenovus Energy, which is valued using quotes for shares on the New York Stock Exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management s best estimate of fair value. Level 3 activity was not material for all periods presented.

Table of Contents

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

	Millions of Dollars								
		December 31, 2018				December 31, 2017			
		Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets									
Investment in Cenovus Energy	$	**1,462**	**-**	**-**	**1,462**	1,899	-	-	1,899
Commodity derivatives		**236**	**181**	**33**	**450**	175	106	30	311
Total assets	$	**1,698**	**181**	**33**	**1,912**	2,074	106	30	2,210
Liabilities									
Commodity derivatives	$	**225**	**145**	**30**	**400**	158	111	41	310
Total liabilities	$	**225**	**145**	**30**	**400**	158	111	41	310

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

	Millions of Dollars					
	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Gross Amounts without Right of Setoff	Net Amounts
December 31, 2018						
Assets	**$ 450**	**280**	**170**	**-**	**9**	**161**
Liabilities	**400**	**280**	**120**	**10**	**4**	**106**
December 31, 2017						
Assets	$ 311	186	125	-	4	121
Liabilities	310	186	124	7	5	112

At December 31, 2018 and December 31, 2017, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

Table of Contents

Non-Recurring Fair Value Measurement

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

		Millions of Dollars		
		Fair Value Measurements Using		
	Fair Value	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Year ended December 31, 2018				
Net PP&E (held for sale)				
March 31, 2018	**$ 250**	**-**	**250**	**44**
September 30, 2018	**201**	**201**	**-**	**43**
Year ended December 31, 2017				
Net PP&E (held for use)				
December 31, 2017	$ 75	-	75	154
Net PP&E (held for sale)				
June 30, 2017	2,830	2,830	-	3,882
December 31, 2017	113	113	-	78
Equity method investments				
June 30, 2017	7,656	-	7,656	2,384

Net PP&E (held for sale)

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

Net PP&E (held for use)

Net PP&E held for use is comprised of various producing properties impaired to their individual fair values. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

Equity Method Investments

During 2017, our investment in APLNG was written down to its fair value of $7,656 million, resulting in a before-tax-charge of $2,384 million. For additional information on APLNG, see Note 6 Investments, Loans and Long-Term Receivables.

Reported Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances related parties.
- Investment in Cenovus Energy shares: See Note 7 Investment in Cenovus Energy for a discussion of the carrying value and fair value of our investment in Cenovus Energy shares.

Table of Contents

Loans and advances related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 6 Investments, Loans and Long-Term Receivables, for additional information.

Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.

Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

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

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2018	2017	**2018**	2017
Financial assets				
Investment in Cenovus Energy	$ **1,462**	1,899	**1,462**	1,899
Commodity derivatives	**170**	125	**170**	125
Total loans and advances related parties	**468**	586	**468**	586
Financial liabilities				
Total debt, excluding capital leases	**14,191**	18,929	**16,147**	22,435
Commodity derivatives	**110**	117	**110**	117

Commodity Derivatives

At December 31, 2018, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $10 million of rights to reclaim cash collateral, respectively. At December 31, 2017, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $7 million of rights to reclaim cash collateral, respectively.

Note 16 Equity

Common Stock

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

	Shares		
	2018	2017	2016
Issued			
Beginning of year	**1,785,419,175**	1,782,079,107	1,778,226,388
Distributed under benefit plans	**6,218,259**	3,340,068	3,852,719

End of year	**1,791,637,434**	1,785,419,175	1,782,079,107
Held in Treasury			
Beginning of year	**608,312,034**	544,809,771	542,230,673
Repurchase of common stock	**44,976,179**	63,502,263	2,579,098
End of year	**653,288,213**	608,312,034	544,809,771

Preferred Stock

We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2018 or 2017.

Table of Contents

Noncontrolling Interests

At December 31, 2018 and 2017, we had $125 million and $194 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control.

Repurchase of Common Stock

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock through 2019. On March 29, 2017, we announced plans to repurchase an additional $3 billion of common stock through 2019. On July 12, 2018, we announced an authorization of an additional $9 billion for share repurchases bringing the total program authorization to $15 billion. Repurchase of shares began in November 2016, and totaled 111,057,540 shares at a cost of $6.1 billion, through December 31, 2018.

Note 17 Non-Mineral Leases

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 11 Debt.

At December 31, 2018, future minimum rental payments due under noncancelable leases were:

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

Operating lease rental expense for the years ended December 31 was:

	Millions of Dollars		
	2018	2017	2016

Total rentals	$	**253**	264	537
Less: sublease rentals		**(16)**	(20)	(10)
	$	**237**	244	527

Table of Contents

Note 18 Employee Benefit Plans

Pension and Postretirement Plans

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

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2018		2017		**2018**	2017
	U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 3,236**	**3,845**	3,416	3,445	**265**	286
Service cost	**83**	**81**	89	77	**1**	2
Interest cost	**99**	**107**	118	103	**8**	9
Plan participant contributions	**-**	**2**	-	2	**22**	23
Plan amendments	**-**	**7**	-	-	**-**	-
Actuarial (gain) loss	**(44)**	**(259)**	244	52	**(10)**	12
Benefits paid	**(507)**	**(143)**	(631)	(117)	**(67)**	(68)
Curtailment	**(4)**	**(3)**	-	-	**-**	-
Settlement	**(730)**	**-**	-	-	**-**	-
Recognition of termination benefits	**3**	**-**	-	-	**-**	-
Foreign currency exchange rate change	**-**	**(199)**	-	283	**(1)**	1
Benefit obligation at December 31*	**$ 2,136**	**3,438**	3,236	3,845	**218**	265
**Accumulated benefit obligation portion of above at December 31:*	***$ 1,969***	***3,066***	*3,076*	*3,404*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 2,541**	**3,647**	2,081	3,068	**-**	-
Actual return on plan assets	**(112)**	**(106)**	336	313	**-**	-
Company contributions	**144**	**156**	755	114	**45**	45
Plan participant contributions	**-**	**2**	-	2	**22**	23
Benefits paid	**(507)**	**(143)**	(631)	(117)	**(67)**	(68)
Settlement	**(730)**	**-**	-	-	**-**	-
Foreign currency exchange rate change	**-**	**(198)**	-	267	**-**	-
Fair value of plan assets at December 31	**$ 1,336**	**3,358**	2,541	3,647	**-**	-
Funded Status	**$ (800)**	**(80)**	(695)	(198)	**(218)**	(265)

Table of Contents

	Millions of Dollars						
	Pension Benefits					Other Benefits	
		2018		2017		**2018**	2017
		U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31							
Noncurrent assets	$	**-**	**232**	-	205	**-**	-
Current liabilities		**(59)**	**(4)**	(38)	(4)	**(44)**	(45)
Noncurrent liabilities		**(741)**	**(308)**	(657)	(399)	**(174)**	(220)
Total recognized	$	**(800)**	**(80)**	(695)	(198)	**(218)**	(265)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31							
Discount rate		**4.25%**	**3.05**	3.55	2.80	**4.05**	3.30
Rate of compensation increase		**4.00**	**3.65**	4.00	3.75	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31							
Discount rate		**3.80%**	**2.90**	3.80	3.00	**3.30**	3.60
Expected return on plan assets		**5.80**	**4.30**	6.55	5.05	**-**	-
Rate of compensation increase		**4.00**	**3.75**	4.00	3.85	**-**	-

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

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

	Millions of Dollars						
	Pension Benefits					Other Benefits	
		2018		2017		**2018**	2017
		U.S.	**Int l.**	U.S.	Int l.		
Unrecognized net actuarial (gain) loss	$	**516**	**310**	588	358	**(21)**	(12)
Unrecognized prior service cost (credit)		**-**	**(4)**	-	(16)	**(216)**	(249)

Table of Contents

	Millions of Dollars						
	Pension Benefits				Other Benefits	
	2018		2017		**2018**	2017
	U.S.	**Int l.**	U.S.	Int l.		
Sources of Change in Other Comprehensive Income (Loss)						
Net gain (loss) arising during the period	$ **(177)**	**17**	(40)	71	**10**	(12)
Amortization of (gain) loss included in income (loss)*	**249**	**31**	200	50	**(1)**	(3)
Net change during the period	$ **72**	**48**	160	121	**9**	(15)
Prior service credit (cost) arising during the period	$ **-**	**(7)**	-	2	**-**	-
Amortization of prior service cost (credit) included in income (loss)	**-**	**(5)**	4	(6)	**(35)**	(36)
Net change during the period	$ **-**	**(12)**	4	(4)	**(35)**	(36)

**Includes settlement losses recognized in 2018 and 2017.*

Included in accumulated other comprehensive loss at December 31, 2018, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2019:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int l.	
Unrecognized net actuarial (gain) loss	$ 52	31	(2)
Unrecognized prior service credit	-	(2)	(33)

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $4,110 million, $3,768 million, and $3,702 million, respectively, at December 31, 2018, and $5,634 million, $5,226 million, and $5,113 million, respectively, at December 31, 2017.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $586 million and $504 million, respectively, at December 31, 2018, and were $578 million and $503 million, respectively, at December 31, 2017.

Table of Contents

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

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2018		2017		2016		**2018**	2017	2016
	U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			
Components of Net Periodic Benefit Cost									
Service cost	$ **83**	**81**	89	77	108	76	**1**	2	2
Interest cost	**99**	**107**	118	103	133	120	**8**	9	13
Expected return on plan assets	**(114)**	**(155)**	(132)	(158)	(149)	(147)	**-**	-	-
Amortization of prior service cost (credit)	**-**	**(5)**	4	(6)	5	(6)	**(35)**	(36)	(34)
Recognized net actuarial loss (gain)	**53**	**31**	69	50	86	26	**(1)**	(3)	(2)
Settlements	**196**	**-**	131	-	202	-	**-**	-	-
Curtailment loss	**-**	**-**	-	-	14	-	**-**	-	1
Net periodic benefit cost	$ **317**	**59**	279	66	399	69	**(27)**	(28)	(20)

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

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

We recognized pension settlement losses of $196 million in 2018, $131 million in 2017, and $202 million in 2016 as lump-sum benefit payments from certain U.S. pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

As part of the 2016 restructuring program, we concluded that actions taken during the year resulted in a significant reduction of future services of active employees primarily in the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as a curtailment loss of $15 million during the year ended December 31, 2016.

Also, as part of the 2016 restructuring program in the United States and Europe, we recognized expense for special termination benefits of $15 million during the year ended December 31, 2016, consisting of $14 million in the United

States and $1 million in Europe.

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

Table of Contents

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 7 percent in 2019 that declines to 5 percent by 2024. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes an ultimate health care cost trend rate of 5 percent achieved in 2019. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

Plan Assets We follow a policy of broadly diversifying pension plan assets across asset classes and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 39 percent equity securities, 54 percent debt securities, 6 percent real estate and 1 percent other. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2018 and 2017.

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

A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2018, the participating interest in the annuity contract was valued at $84 million and consisted of $228 million in debt securities, less $144 million for the accumulated

Table of Contents

benefit obligation covered by the contract. At December 31, 2017, the participating interest in the annuity contract was valued at $99 million and consisted of $265 million in debt securities, less $166 million for the accumulated benefit obligation covered by the contract. The net change from 2017 to 2018 is due to a decrease in the fair value of the underlying investments of $37 million offset by a decrease in the present value of the contract obligation of $22 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

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

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

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

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

Table of Contents

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

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2017								
Equity securities								
U.S.	$ 161	-	14	175	440	-	-	440
International	178	-	-	178	315	-	-	315
Mutual funds	146	-	-	146	292	165	-	457
Debt securities								
Government	-	-	-	-	902	-	-	902
Corporate	-	2	-	2	-	-	-	-
Mutual funds	-	-	-	-	144	-	-	144
Cash and cash equivalents	-	-	-	-	111	-	-	111
Time deposits	-	-	-	-	3	-	-	3
Derivatives	-	-	-	-	5	-	-	5
Real estate	-	-	-	-	-	-	123	123
Total in fair value hierarchy	$ 485	2	14	501	2,212	165	123	2,500
Investments measured at net asset value*								
Equity securities								
Common/collective trusts	$ -	-	-	805	-	-	-	183
Debt securities								
Corporate	-	-	-	-	-	-	-	172
Agency and mortgage-backed securities	-	-	-	-	-	-	-	15
Common/collective trusts	-	-	-	1,042	-	-	-	648
Cash and cash equivalents	-	-	-	17	-	-	-	24
Real estate	-	-	-	74	-	-	-	94
Total**	$ 485	2	14	2,439	2,212	165	123	3,636

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

***Excludes the participating interest in the insurance annuity contract with a net asset value of $99 million and net payables related to security transactions of $14 million.*

Level 3 activity was not material for all periods.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2019, we expect to contribute approximately $195 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $185 million to our international qualified and nonqualified pension and postretirement benefit plans.

Table of Contents

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

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int l.	
2019	$ 400	123	36
2020	251	129	34
2021	232	137	30
2022	222	138	27
2023	216	143	24
2024 2027	880	788	69

Severance Accrual

As a result of staff reductions occurring throughout the year, severance accruals of $70 million were recorded in 2018. The following table summarizes our severance accrual activity for the year ended December 31, 2018:

	Millions of Dollars
Balance at December 31, 2017	$ 53
Accruals	**70**
Benefit payments	**(73)**
Foreign currency translation adjustments	**(2)**
Balance at December 31, 2018	**$ 48**

Of the remaining balance at December 31, 2018, $23 million is classified as short-term.

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 34 investment options. Employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Effective January 1, 2019, new employees, rehires, and employees that elected to opt out of Title II will be eligible to receive a CRC of 6 percent of eligible pay into their CPSP. After three years of service with the company, the employee is 100 percent vested in any CRC. Company contributions charged to expense for the CPSP and predecessor plans were $82 million in 2018, $77 million in 2017, and $58 million in 2016.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $31 million in 2018, $35 million in 2017, and $44 million in 2016.

Share-Based Compensation Plans

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

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

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

	Millions of Dollars		
	2018	2017	2016
Compensation cost	**$ 265**	227	272
Tax benefit	**64**	76	92

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

The fair market values of the options granted in 2017 and 2016 were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

	2017	2016
Assumptions used		
Risk-free interest rate	2.24 %	1.55

Dividend yield	4.00 %	4.00
Volatility factor	28.12 %	26.80
Expected life (years)	6.39	6.37

There were no ranges in the assumptions used to determine the fair market values of our options granted in 2017 and 2016.

132

We believe our historical volatility for periods prior to the 2012 separation of our Downstream businesses is no longer relevant in estimating expected volatility. For 2017 and 2016, expected volatility was based on the weighted-average blend of the company s historical stock price volatility from May 1, 2012 (the date of separation of our Downstream businesses) through the stock option grant date and the average historical stock price volatility of a group of peer companies for the expected term of the options.

The following summarizes our stock option activity for the year ended December 31, 2018:

			Millions of Dollars
	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding at December 31, 2017	24,722,803	$ 52.18	$ 177
Exercised	**(3,903,130)**	**45.71**	**94**
Forfeited	**(84,694)**	**58.23**	
Expired or cancelled	**(1,355,302)**	**60.53**	
Outstanding at December 31, 2018	**19,379,677**	**$ 52.88**	**$ 214**
Vested at December 31, 2018	**18,820,388**	**$ 53.16**	**$ 204**
Exercisable at December 31, 2018	**16,213,002**	**$ 54.89**	**$ 152**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2018, was 5.16 years, 5.09 years and 4.69 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2017 and 2016 was $9.18 and $5.39, respectively. The aggregate intrinsic value of options exercised was $4 million in 2017 and zero in 2016.

During 2018, we received $178 million in cash and realized a tax benefit of $18 million from the exercise of options. At December 31, 2018, the remaining unrecognized compensation expense from unvested options was $2 million, which will be recognized over a weighted-average period of 0.87 years, the longest period being 1.12 years.

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

Stock-Settled

Upon vesting, these restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

Table of Contents

The following summarizes our stock-settled stock unit activity for the year ended December 31, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	7,826,852	$ 45.75	
Granted	**2,465,100**	**52.45**	
Forfeited	**(173,265)**	**45.72**	
Issued	**(2,571,714)**		**$ 154**
Outstanding at December 31, 2018	**7,546,973**	**$ 43.41**	
Not Vested at December 31, 2018	**5,090,209**	**43.69**	

At December 31, 2018, the remaining unrecognized compensation cost from the unvested stock-settled units was $88 million, which will be recognized over a weighted-average period of 1.68 years, the longest period being 2.76 years. The weighted-average grant date fair value of stock unit awards granted during 2017 and 2016 was $48.77 and $32.15, respectively. The total fair value of stock units issued during 2017 and 2016 was $159 million and $191 million, respectively.

Cash-Settled

Beginning in 2018, cash-settled executive restricted stock units replaced the stock option program. These restricted stock units, subject to elections to defer, will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not settled until the earlier of separation from the company or the end of the regularly scheduled vesting period. Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the settlement date. Recipients receive an accrued reinvested dividend equivalent that is charged to compensation expense. The accrued reinvested dividend is paid at the time of settlement, subject to the terms and conditions of the award.

The following summarizes our cash-settled stock unit activity for the year ended December 31, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	-	$ -	
Granted	**393,571**	**53.68**	

Forfeited	**(3,849)**		**59.17**	
Issued	**(13,114)**			**$ 1**
Outstanding at December 31, 2018	**376,608**	**$**	**62.21**	
Not Vested at December 31, 2018	**90,254**		**62.21**	

At December 31, 2018, the remaining unrecognized compensation cost from the unvested cash-settled units was $3 million, which will be recognized over a weighted-average period of 1.79 years, the longest period being 2.12 years.

134

Table of Contents

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

Stock-Settled

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

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	2,753,465	$ 50.79	
Granted	**19,708**	**53.28**	
Forfeited	**(2,859)**	**48.89**	
Issued	**(434,772)**		**$ 29**
Outstanding at December 31, 2018	**2,335,542**	**$ 50.45**	
Not Vested at December 31, 2018	**58,914**	**$ 48.41**	

At December 31, 2018, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was zero. The weighted-average grant date fair value of stock-settled PSUs granted during 2017 and 2016 was $49.76 and $33.13, respectively. The total fair value of stock-settled PSUs issued during 2017 and 2016 was $57 million and $17 million, respectively.

Cash-Settled

In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending at the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. For performance periods beginning before 2018, during the performance period, recipients of the PSUs do not receive a quarterly cash payment of a dividend equivalent, but after the performance period ends, until settlement in cash occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense. For the performance period beginning in 2018, recipients of the PSUs receive an accrued reinvested dividend equivalent that is charged to compensation expense. The accrued reinvested dividend is paid at the time of settlement, subject to the terms and conditions of the award.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2018:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2017	1,214,533	$55.19	
Granted	**321,965**	**53.28**	
Forfeited	**(9,282)**	**59.17**	
Settled	**(396,209)**		**$22**
Outstanding at December 31, 2018	**1,131,007**	**$62.21**	
Not Vested at December 31, 2018	**87,900**	**$62.21**	

At December 31, 2018, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $1 million, which will be recognized over a weighted-average period of 0.89 years, the longest period being 1.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2017 and 2016 was $49.76 and $33.13, respectively. The total fair value of cash-settled performance share awards settled during 2017 and 2016 was $24 million and $31 million, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards terminated at the end of the three-year performance period and were replaced with approved

PSU awards. For the open performance period beginning in 2013, the initial target PSU awards terminated at the end of the three-year performance period and were settled after the performance period ended. There is no effect on recognition of compensation expense.

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

Table of Contents

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2018:

			Millions of Dollars
		Weighted-Average	
	Stock Units	Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2017	1,301,040	$ 45.77	
Granted	**70,922**	**62.01**	
Cancelled	**(1,334)**	**23.09**	
Issued	**(263,313)**		**$ 17**
Outstanding at December 31, 2018	**1,107,315**	**$ 46.57**	
Not Vested at December 31, 2018	**-**		

At December 31, 2018, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2017 and 2016 was $48.87 and $40.36, respectively. The total fair value of awards issued during 2017 and 2016 was $4 million and $2 million, respectively.

Note 19 Income Taxes

Income taxes charged to net income (loss) were:

	Millions of Dollars		
	2018	2017	2016
Income Taxes			
Federal			
Current	$ **4**	79	(9)
Deferred	**545**	(3,046)	(1,634)
Foreign			
Current	**3,273**	1,729	393
Deferred	**(166)**	(510)	(519)
State and local			
Current	**108**	51	(135)
Deferred	**(96)**	(125)	(67)
	$ **3,668**	(1,822)	(1,971)

137

Table of Contents

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

	Millions of Dollars	
	2018	2017
Deferred Tax Liabilities		
PP&E and intangibles	$ **8,004**	9,692
Inventory	**60**	61
Deferred state income tax	**61**	178
Other	**156**	464
Total deferred tax liabilities	**8,281**	10,395
Deferred Tax Assets		
Benefit plan accruals	**641**	786
Asset retirement obligations and accrued environmental costs	**2,891**	3,060
Investments in joint ventures	**104**	57
Other financial accruals and deferrals	**330**	166
Loss and credit carryforwards	**2,378**	2,310
Other	**398**	152
Total deferred tax assets	**6,742**	6,531
Less: valuation allowance	**(3,040)**	(1,254)
Net deferred tax assets	**3,702**	5,277
Net deferred tax liabilities	$ **4,579**	5,118

At December 31, 2018, noncurrent assets and liabilities included deferred taxes of $442 million and $5,021 million, respectively. At December 31, 2017, noncurrent assets and liabilities included deferred taxes of $164 million and $5,282 million, respectively.

At December 31, 2018, the components of our loss and credit carryforwards before and after consideration of the applicable valuation allowances were:

	Millions of Dollars		
	Gross Deferred Tax Asset	Net Deferred Tax Asset After Valuation Allowance	Expiration of Net Deferred

			Tax Asset
U.S. foreign tax credits	$ 1,016	17	2027
U.S. general business credits	364	364	2036-2038
State net operating losses and tax credits	312	32	Various
Foreign net operating losses and tax credits	686	647	Post 2025
	$ 2,378	1,060	

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2018, valuation allowances increased a total of $1,786 million. The increase primarily relates to deferred tax assets recognized during 2018 as a result of the U.S. Tax Cuts and Jobs Act (Tax Legislation), as further discussed below, and are related to U.S. tax basis and foreign tax credits associated with our foreign branch assets that we do not expect to realize. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects deferred tax assets, net of valuation allowance, will primarily be realized as offsets to reversing deferred tax liabilities.

Table of Contents

At December 31, 2018, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,808 million. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. The estimated amount of additional tax, primarily local withholding tax, that would be payable on this income if distributed is approximately $190 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2018, 2017 and 2016:

	Millions of Dollars		
	2018	2017	2016
Balance at January 1	**$ 882**	381	459
Additions based on tax positions related to the current year	**268**	612	32
Additions for tax positions of prior years	**43**	109	19
Reductions for tax positions of prior years	**(73)**	(129)	(118)
Settlements	**(35)**	(5)	(9)
Lapse of statute	**(4)**	(86)	(2)
Balance at December 31	**$ 1,081**	882	381

Included in the balance of unrecognized tax benefits for 2018, 2017 and 2016 were $1,081 million, $882 million and $359 million, respectively, which, if recognized, would impact our effective tax rate. The balance of the unrecognized tax benefits increased in 2018 mainly due to the treatment of distributions from certain of foreign subsidiaries. The balance of unrecognized tax benefits increased in 2017 mainly due to the recognition of a U.S. worthless securities deduction that we do not believe will generate a cash tax benefit.

At December 31, 2018, 2017 and 2016, accrued liabilities for interest and penalties totaled $45 million, $54 million and $54 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings of $4 million in 2018, no impact to earnings in 2017, and a benefit to earnings of $18 million in 2016.

We file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2015), Canada (2010), United States (2014) and Norway (2017). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. Consequently, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

Table of Contents

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

	Millions of Dollars			Percent of Pre-Tax Income (Loss)		
	2018	2017	2016	**2018**	2017	2016
Income (loss) before income taxes						
United States	**$ 2,867**	(5,250)	(4,410)	**28.7%**	200.8	79.7
Foreign	**7,106**	2,635	(1,120)	**71.3**	(100.8)	20.3
	$ 9,973	(2,615)	(5,530)	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 2,095**	(915)	(1,936)	**21.0%**	35.0	35.0
Non-U.S. effective tax rates	**1,766**	625	361	**17.7**	(23.9)	(6.5)
Tax Legislation	**(10)**	(852)	-	**(0.1)**	32.6	-
Canada disposition	**-**	(1,277)	-	**-**	48.8	-
U.K. disposition	**(150)**	-	-	**(1.5)**	-	-
Recovery of outside basis	**(21)**	(962)	(60)	**(0.2)**	36.8	1.1
Adjustment to tax reserves	**(4)**	881	55	**-**	(33.7)	(1.0)
Adjustment to valuation allowance	**(26)**	-	-	**(0.3)**	-	-
APLNG impairment	**-**	834	-	**-**	(31.9)	-
State income tax	**135**	(84)	(122)	**1.4**	3.2	2.2
Enhanced oil recovery credit	**(99)**	(68)	(62)	**(1.0)**	2.6	1.1
U.K. rate change	**-**	-	(161)	**-**	-	2.9
Other	**(18)**	(4)	(46)	**(0.2)**	0.2	0.8
	$ 3,668	(1,822)	(1,971)	**36.8%**	69.7	35.6

The decrease in the effective tax rate for 2018 was primarily due to the impact of the Clair Field disposition in the U.K. and our overall income position, partially offset by our mix of income among taxing jurisdictions.

Our effective tax rate for 2018 was favorably impacted by the sale of a ConocoPhillips subsidiary to BP. The subsidiary held a 16.5 percent interest in the BP-operated Clair Field in the United Kingdom. The disposition generated a before-tax gain of $715 million with no associated tax cost. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions for additional information on the U.K. disposition.

Tax Legislation was enacted in the United States on December 22, 2017, reducing the U.S. federal corporate income tax rate to 21 percent from 35 percent, requiring companies to pay a one-time transition tax on earnings of certain foreign subsidiaries that were previously tax deferred and creating new taxes on certain foreign-sourced earnings.

SAB 118 measurement period

We applied the guidance in Staff Accounting Bulletin No. 118 when accounting for the enactment-date effects of Tax Legislation in 2017 and throughout 2018. At December 31, 2017, we had not completed our accounting for all the enactment-date income tax effects of Tax Legislation under ASC 740, Income Taxes, for the remeasurement of deferred tax assets and liabilities and the one-time transition tax. As of December 31, 2018, we have now completed our accounting for all the enactment-date income tax effects of Tax Legislation. As further discussed below, during 2018, we recognized adjustments of $10 million to the provisional amounts recorded at December 31, 2017, and included these adjustments as a component of income tax provision.

Provisional Amounts Foreign tax effects

The one-time transition tax is based on our total post-1986 earnings, the tax on which we previously deferred from U.S. income taxes under U.S. law. We estimated at December 31, 2017, that we would not incur a one-time transition tax. Upon further analyses of Tax Legislation and Notices and regulations issued and proposed by the U.S. Department of the Treasury and the Internal Revenue Service, we finalized our calculations of the transition tax liability during 2018. Based upon this analysis, we did not incur a one-time transition tax.

Table of Contents

As a result of the Tax Legislation, we removed the indefinite reinvestment assertion on one of our foreign subsidiaries and recorded a tax expense of $56 million in the fourth quarter of 2017.

Deferred tax assets and liabilities

As of December 31, 2017, we remeasured certain deferred tax assets and liabilities based on the rates at which they were expected to reverse in the future (which was generally 21 percent), by recording a provisional amount of $908 million. Upon further analysis of certain aspects of Tax Legislation and refinement of our calculations during the 12 months ended December 31, 2018, we adjusted our provisional amount by $10 million, which is included as a component of income tax expense.

Global intangible low-taxed income (GILTI)

We have elected to account for GILTI in the year the tax is incurred. At December 31, 2018, the current-year U.S. income tax impact related to GILTI activities is immaterial.

Our effective tax rate in 2017 was favorably impacted by a tax benefit of $1,277 million related to the Canada disposition. This tax benefit was primarily associated with a deferred tax recovery related to the Canadian capital gains exclusion component of the 2017 Canada disposition and the recognition of previously unrealizable Canadian capital asset tax basis. The Canada disposition, along with the associated restructuring of our Canadian operations, may generate an additional tax benefit of $822 million. However, since we believe it is not likely we will receive a corresponding cash tax savings, this $822 million benefit has been offset by a full tax reserve. See Note 5 Assets Held for Sale, Sold or Acquired and Other Planned Dispositions for additional information on our Canada disposition.

The impairment of our APLNG investment in the second quarter of 2017 did not generate a tax benefit. See the APLNG section of Note 6 Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment.

The decrease in the effective tax rate for 2016 was primarily due to our mix of income among taxing jurisdictions, reduced net tax benefit from the tax law changes discussed below, and the absence of a tax benefit associated with electing the fair market value method of apportioning interest expense for prior years.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, we recorded a $161 million net tax benefit related to the remeasurement of our U.K. deferred tax balance in 2016.

Certain operating losses in jurisdictions outside of the United States only yield a tax benefit in the United States as a worthless security deduction. For 2018, 2017 and 2016, before consideration of unrecorded tax benefits discussed above, the amount of the tax benefit was $36 million, $962 million and $60 million, respectively.

Table of Contents

Note 20 Accumulated Other Comprehensive Loss

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

	Millions of Dollars			
	Defined Benefit Plans	Net Unrealized Loss on Securities	Foreign Currency Translation	Accumulated Other Comprehensive Loss
December 31, 2015	$ (443)	-	(5,804)	(6,247)
Other comprehensive income (loss)	(104)	-	158	54
December 31, 2016	(547)	-	(5,646)	(6,193)
Other comprehensive income (loss)	147	(58)	586	675
December 31, 2017	(400)	(58)	(5,060)	(5,518)
Other comprehensive income (loss)	**39**	**-**	**(642)**	**(603)**
Cumulative effect of adopting ASU No. 2016-01*	**-**	**58**	**-**	**58**
December 31, 2018	**$ (361)**	**-**	**(5,702)**	**(6,063)**

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

There were no items within accumulated other comprehensive loss related to noncontrolling interests.

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

	Millions of Dollars	
	2018	2017
Defined Benefit Plans	**$ 189**	135
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	***$ 50***	*74*

See Note 18 Employee Benefit Plans, for additional information.

142

Table of Contents

Note 21 Cash Flow Information

	Millions of Dollars		
	2018	2017	2016
Noncash Investing Activities			
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	**$ 395**	(37)	(1,017)
Increase (decrease) in assets and liabilities acquired in a nonmonetary exchange*			
Accounts receivable	**(44)**	-	-
Inventories	**42**	-	-
Investments and long-term receivables	**15**	-	-
PP&E	**1,907**	-	-
Other long-term assets	**(9)**	-	-
Accounts payable	**7**	-	-
Accrued income and other taxes	**40**	-	-
Cash Payments (Receipts)			
Interest	**$ 772**	1,163	1,151
Income taxes	**2,976**	1,168	(318)**
Net Sales (Purchases) of Short-Term Investments			
Short-term investments purchased	**$ (1,953)**	(6,617)	(1,753)
Short-term investments sold	**3,573**	4,827	1,702
	$ 1,620	(1,790)	(51)

**See Note 5 Assets Held for Sale, Sold, or Acquired and Other Planned Dispositions.*

***2016 is net of $585 million related to refunds received from the Internal Revenue Service.*

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

In 2018, we collected $430 million from PDVSA consisting of $230 million from the sale of commodity inventory and $200 million in cash, as partial payments related to an award issued by the ICC Tribunal in 2018. We collected $262 million and $75 million from Ecuador in 2018 and 2017, respectively, as installment payments related to an agreement reached with Ecuador in 2017. For more information on these settlements, see Note 13 Contingencies and Commitments.

We made discretionary payments to our domestic qualified pension plan of $120 million and $600 million in 2018 and 2017, respectively.

In 2017, we recognized a $180 million adverse cash impact from the settlement of cross-currency swap transactions.

Table of Contents

Note 22 Other Financial Information

	Millions of Dollars		
	2018	2017	2016
Interest and Debt Expense			
Incurred			
Debt	$ **838**	1,114	1,279
Other	**67**	103	123
	905	1,217	1,402
Capitalized	**(170)**	(119)	(157)
Expensed	$ **735**	1,098	1,245
Other Income			
Interest income	$ **97**	112	57
Other, net	**76**	417	198
	$ **173**	529	255
Research and Development Expenditures expensed	$ **78**	100	116
Shipping and Handling Costs*	$ **1,075**	1,050	1,140

**Amounts included in production and operating expenses. 2017 and 2016 have been reclassified to conform to the current-period presentation resulting from the adoption of ASU No. 2017-07. See Note 2 Changes in Accounting Principles, for additional information.*

Foreign Currency Transaction (Gains) Losses after-tax			
Alaska	$ **-**	-	-
Lower 48	**-**	-	-
Canada	**(11)**	3	1
Europe and North Africa	**(26)**	7	(7)
Asia Pacific and Middle East	**3**	23	(9)
Other International	**-**	1	7
Corporate and Other	**21**	(3)	(18)
	$ **(13)**	31	(26)

	Millions of Dollars	
	2018	2017
Properties, Plants and Equipment		
Proved properties	**$ 100,657**	102,044
Unproved properties	**4,662**	4,491
Other	**5,278**	3,896
Gross properties, plants and equipment	**110,597**	110,431
Less: Accumulated depreciation, depletion and amortization	**(64,899)**	(64,748)
Net properties, plants and equipment	**$ 45,698**	45,683

Note 23 Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

	Millions of Dollars		
	2018	2017	2016
Operating revenues and other income	$ **98**	107	133
Purchases	**98**	99	101
Operating expenses and selling, general and administrative expenses	**60**	59	63
Net interest (income) expense*	**(14)**	(13)	(12)

**We paid interest to, or received interest from, various affiliates. See Note 6 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

The table above includes transactions with the FCCL Partnership through the date of the sale. See Note 6 Investments, Loans and Long-Term Receivables, for additional information.

Note 24 Sales and Other Operating Revenues

Transitional Arrangements

We adopted the provisions of ASC Topic 606 beginning January 1, 2018, using the modified retrospective approach, which we have applied to contracts within the scope of the standard that had not been completed as of January 1, 2018. Results for reporting periods beginning after January 1, 2018, are presented under ASC Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with ASC Topic 605. See Note 2 Changes in Accounting Principles for the effect on our consolidated balance sheet and the line items which have been impacted by the adoption of this standard.

The cumulative effect of applying the standard relates solely to certain licensing arrangements where revenue was previously recognized ($61 million in 2011, $146 million in 2015, and $44 million in 2017) based on contractual milestones. Under ASC Topic 606, such revenues are recognized when the customer has the ability to utilize and benefit from its right to use the license. As a result, such historically recognized revenues must be reversed through a cumulative effect adjustment and deferred until such time when the customer has the ability to utilize and benefit from the license. The cumulative effect adjustment relates to contracts that were not substantially completed at the date of implementation.

Practical Expedients

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

Table of Contents

Revenue from Contracts with Customers

The following table provides further disaggregation of our consolidated sales and other operating revenues:

	Millions of Dollars		
	2018	2017*	2016*
Revenue from contracts with customers	**$ 28,098**	20,525	16,527
Revenue from contracts outside the scope of ASC Topic 606			
Physical contracts meeting the definition of a derivative	**8,218**	8,669	7,278
Financial derivative contracts	**101**	(88)	(112)
Consolidated sales and other operating revenues	**$ 36,417**	29,106	23,693

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

Revenues from contracts outside the scope of ASC Topic 606 relate primarily to physical gas contracts at market prices which qualify as derivatives accounted for under ASC Topic 815, Derivatives and Hedging, and for which we have not elected normal purchases and normal sales (NPNS). There is no significant difference in contractual terms or the policy for recognition of revenue from these contracts and those within the scope of ASC Topic 606. The following disaggregation of revenues is provided in conjunction with Note 25 Segment Disclosures and Related Information:

	Millions of Dollars		
	2018	2017*	2016*
Revenue from Outside the Scope of ASC Topic 606 by Segment			
Lower 48	**$ 6,358**	6,302	5,391
Canada	**629**	864	813
Europe and North Africa	**1,231**	1,503	1,074
Physical contracts meeting the definition of a derivative	**$ 8,218**	8,669	7,278

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

	Millions of Dollars		
	2018	2017*	2016*

Revenue from Outside the Scope of ASC Topic 606 by Product			
Crude oil	**$ 1,112**	588	436
Natural gas	**6,734**	7,811	6,502
Other	**372**	270	340
Physical contracts meeting the definition of a derivative	**$ 8,218**	8,669	7,278

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

Receivables and Contract Liabilities

Receivables from Contracts with Customers

At December 31, 2018, the Accounts and notes receivable line on our consolidated balance sheet included trade receivables of $2,889 million compared with $2,675 million at December 31, 2017, and included both contracts with customers within the scope of ASC Topic 606 and those that are outside the scope of ASC Topic 606. We typically receive payment within 30 days or less (depending on the terms of the invoice) once delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical gas sales contracts at market prices for which we do not elect NPNS and are therefore accounted for as a derivative

under ASC Topic 815. There is little distinction in the nature of the customer or credit quality of trade receivables associated with gas sold under contracts for which NPNS has not been elected compared with trade receivables where NPNS has been elected.

Table of Contents

Contract Liabilities from Contracts with Customers

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

		Millions of Dollars
Contract Liabilities		
At January 1, 2018	$	**251**
Contractual payments received		**103**
Revenue recognized		**(148)**
At December 31, 2018	**$**	**206**
Amounts Recognized in the Consolidated Balance Sheet at December 31, 2018		
Current liabilities	$	**169**
Noncurrent liabilities		**37**
	$	**206**

During 2018, we recognized revenue of $148 million in the Sales and other operating revenues line on our consolidated income statement. We expect to recognize the contract liabilities as of December 31, 2018, as revenue between the remainder of 2019 and 2022 as construction is completed.

Prior to the adoption of ASC Topic 606, contractual cash payments received were recognized as Sales and other operating revenues when received.

Note 25 Segment Disclosures and Related Information

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

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, premiums on early retirement of debt, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents and short-term investments.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1 Accounting Policies. Intersegment sales are at prices that approximate market.

147

Table of Contents

Analysis of Results by Operating Segment

	Millions of Dollars		
	2018	2017	2016
Sales and Other Operating Revenues			
Alaska	**$ 5,740**	4,224	3,681
Lower 48	**17,029**	12,968	10,719
Intersegment eliminations	**(40)**	(4)	(17)
Lower 48	**16,989**	12,964	10,702
Canada	**3,184**	3,178	2,192
Intersegment eliminations	**(1,160)**	(559)	(218)
Canada	**2,024**	2,619	1,974
Europe and North Africa	**6,635**	5,181	3,462
Asia Pacific and Middle East	**4,861**	4,014	3,705
Corporate and Other	**168**	104	169
Consolidated sales and other operating revenues	**$ 36,417**	29,106	23,693
Depreciation, Depletion, Amortization and Impairments			
Alaska	**$ 760**	1,026	868
Lower 48	**2,370**	6,693	4,358
Canada	**324**	461	975
Europe and North Africa	**1,041**	1,313	1,253
Asia Pacific and Middle East	**1,382**	3,819	1,606
Other International	**-**	-	1
Corporate and Other	**106**	134	140
Consolidated depreciation, depletion, amortization and impairments	**$ 5,983**	13,446	9,201

In 2018, sales by our Lower 48, Alaska and Canada segments to a certain refining company accounted for approximately $4 billion or 11 percent of our total consolidated sales and other operating revenues.

Table of Contents

		Millions of Dollars		
		2018	2017	2016
Equity in Earnings of Affiliates				
Alaska	$	**6**	7	9
Lower 48		**1**	5	(6)
Canada		**-**	197	89
Europe and North Africa		**16**	10	22
Asia Pacific and Middle East		**1,051**	553	(51)
Other International		**-**	-	-
Corporate and Other		**-**	-	(11)
Consolidated equity in earnings of affiliates	$	**1,074**	772	52
Income Taxes				
Alaska	$	**376**	(689)	(59)
Lower 48		**474**	(2,453)	(1,328)
Canada		**(96)**	(616)	(383)
Europe and North Africa		**2,265**	1,165	(46)
Asia Pacific and Middle East		**722**	351	306
Other International		**30**	21	(40)
Corporate and Other		**(103)**	399	(421)
Consolidated income taxes	$	**3,668**	(1,822)	(1,971)
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$	**1,814**	1,466	319
Lower 48		**1,747**	(2,371)	(2,257)
Canada		**63**	2,564	(935)
Europe and North Africa		**1,866**	553	394
Asia Pacific and Middle East		**2,070**	(1,098)	209
Other International		**364**	167	(16)
Corporate and Other		**(1,667)**	(2,136)	(1,329)
Consolidated net income (loss) attributable to ConocoPhillips	$	**6,257**	(855)	(3,615)
Investments in and Advances to Affiliates				
Alaska	$	**86**	56	58
Lower 48		**378**	402	426
Canada		**-**	-	8,784
Europe and North Africa		**55**	55	62
Asia Pacific and Middle East		**8,821**	9,077	11,611
Other International		**-**	-	-
Corporate and Other		**-**	-	4

Consolidated investments in and advances to affiliates	$	**9,340**	9,590	20,945

149

Table of Contents

		Millions of Dollars	
	2018	2017	2016
Total Assets			
Alaska	$ **14,648**	12,108	12,314
Lower 48	**14,888**	14,632	22,673
Canada	**5,748**	6,214	17,548
Europe and North Africa	**9,883**	11,870	11,727
Asia Pacific and Middle East	**16,151**	16,985	20,451
Other International	**89**	97	97
Corporate and Other	**8,573**	11,456	4,962
Consolidated total assets	$ **69,980**	73,362	89,772
Capital Expenditures and Investments			
Alaska	$ **1,298**	815	883
Lower 48	**3,184**	2,136	1,262
Canada	**477**	202	698
Europe and North Africa	**877**	872	1,020
Asia Pacific and Middle East	**718**	482	838
Other International	**6**	21	104
Corporate and Other	**190**	63	64
Consolidated capital expenditures and investments	$ **6,750**	4,591	4,869
Interest Income and Expense			
Interest income			
Corporate	$ **80**	101	47
Lower 48	**-**	-	-
Europe and North Africa	**2**	2	2
Asia Pacific and Middle East	**15**	9	8
Other International	**-**	-	-
Interest and debt expense Corporate	$ **735**	1,098	1,245
Sales and Other Operating Revenues by Product			
Crude oil	$ **19,571**	13,260	10,801
Natural gas	**10,720**	10,773	9,401
Natural gas liquids	**1,114**	1,102	837
Other*	**5,012**	3,971	2,654
Consolidated sales and other operating revenues by product	$ **36,417**	29,106	23,693

**Includes LNG and bitumen.*

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
	2018	2017	2016	**2018**	2017	2016
United States	**$ 22,740**	17,204	14,400	**26,838**	23,623	32,949
Australia[3]	**1,798**	1,448	1,353	**9,301**	9,657	12,259
Canada	**2,024**	2,619	1,974	**5,333**	5,613	16,846
China	**836**	712	551	**1,380**	1,275	1,372
Indonesia	**886**	757	938	**669**	758	856
Libya[4]	**1,142**	586	-	**679**	699	704
Malaysia	**1,346**	1,103	735	**2,327**	2,736	3,323
Norway	**2,886**	2,348	1,645	**5,582**	6,154	6,228
United Kingdom	**2,606**	2,248	1,816	**1,583**	3,335	3,209
Other foreign countries	**153**	81	281	**1,346**	1,423	1,530
Worldwide consolidated	**$ 36,417**	29,106	23,693	**55,038**	55,273	79,276

(1)Sales and other operating revenues are attributable to countries based on the location of the selling operation.

(2)Defined as net PP&E plus investments in and advances to affiliated companies.

(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.

(4)Included in Other foreign countries in prior periods.

Note 26 New Accounting Standards

In February 2016, the FASB issued ASU No. 2016-02, Leases (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, Leases (FASB ASC Topic 840), and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements.

ASU No. 2016-02 was amended in January 2018 by the provisions of ASU No. 2018-01, Land Easement Practical Expedient for Transition to Topic 842 (ASU No. 2018-01), and in July 2018 by the provisions of ASU No. 2018-10, Codification Improvements to Topic 842, Leases (ASU No. 2018-10). In addition, ASU No. 2016-02 was further amended in July 2018 by the provisions of ASU No. 2018-11, Targeted Improvements (ASU No. 2018-11), and in December 2018 by the provisions of ASU No. 2018-20, Narrow-Scope Improvements for Lessors (ASU No. 2018-20).

ASU No. 2018-11 sets forth certain additional practical expedients for lessors and provides entities with an option to apply the provisions of ASU No. 2016-02, as amended, to leasing arrangements existing at or entered into after the ASU s effective date of adoption (the Optional Transition Method). Entities that elect to utilize the Optional Transition Method would not apply the provisions of ASU No. 2016-02, as amended, to comparative periods presented in the financial statements.

We plan to adopt ASU No. 2016-02, as amended, effective January 1, 2019, utilizing the Optional Transition Method. Accordingly, the comparative periods presented in the financial statements prior to January 1, 2019, will be presented pursuant to the existing requirements of FASB ASC Topic 840 and not be adjusted upon the adoption of the ASU. We also expect to utilize the package of optional transition-related practical expedients set forth by ASU No. 2016-02, as amended, which permit entities to not reassess upon the adoption of the ASU certain historical conclusions regarding lease contract identification and classification, as well as the historical accounting treatment of initial direct costs (the Package of Optional Practical Expedients). For lease arrangements containing both lease and non-lease components, we will adopt the optional practical expedient to not separate lease components from non-lease components for all new or modified leases executed on or after the effective date of the ASU, subject to making any elections for leases after the effective date in new asset classes. Furthermore, we do not expect to record assets and liabilities on our consolidated balance sheet for new or existing lease arrangements with terms of 12 months or less.

The expected impact of the adoption of ASU No. 2016-02, as amended, relates primarily to our balance sheet, resulting from the initial recognition of lease liabilities and corresponding right-of-use assets for our existing population of operating leases, as well as enhanced disclosure of our leasing arrangements. We expect to recognize on our consolidated balance sheet approximately $1 billion of operating lease liabilities and corresponding right-of-use assets upon the adoption of ASU No. 2016-02, as amended. We have implemented a third-party lease accounting software solution to facilitate the ongoing accounting and financial reporting requirements of the ASU and also expect the adoption of the ASU to result in certain changes being made to our existing accounting policies and systems, business processes, and internal controls.

While our evaluation of ASU No. 2016-02, as amended, and related implementation activities approach completion, we continue to monitor proposals issued by the FASB to clarify the ASU.

In June 2016, the FASB issued ASU No. 2016-13, Measurement of Credit Losses on Financial Instruments (ASU No. 2016-13), which sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments based on expected losses rather than incurred losses. The ASU is effective for interim and annual periods beginning after December 15, 2019, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

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

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the economic interest method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2018, approximately 6 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 5 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, and Africa.

Reserves Governance

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

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geoscientists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit s reserves

Table of Contents

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

During 2018, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2018, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management s intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M s opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2018, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M s report is included as Exhibit 99 of this Annual Report on Form 10-K.

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

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

Table of Contents

Proved Reserves

Years Ended December 31	Crude Oil Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2015	915	588	1,503	14	346	203	204	2,270
Revisions	(57)	(93)	(150)	3	-	6	-	(141)
Improved recovery	6	3	9	-	-	7	-	16
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	33	79	112	-	-	7	-	119
Production	(60)	(71)	(131)	(3)	(43)	(35)	(1)	(213)
Sales	-	-	-	(1)	-	(3)	-	(4)
End of 2016	837	506	1,343	13	303	185	203	2,047
Revisions	113	65	178	1	38	32	-	249
Improved recovery	6	-	6	-	-	-	-	6
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	41	210	251	-	-	2	-	253
Production	(60)	(64)	(124)	(1)	(45)	(34)	(7)	(211)
Sales	-	(10)	(10)	(12)	-	-	-	(22)
End of 2017	937	707	1,644	1	296	185	196	2,322
Revisions	72	(90)	(18)	2	24	6	5	19
Improved recovery	2	-	2	-	-	-	-	2
Purchases	233	1	234	-	-	-	-	234
Extensions and discoveries	48	179	227	2	2	1	-	232
Production	(59)	(82)	(141)	(1)	(40)	(33)	(13)	(228)
Sales	-	(12)	(12)	-	(36)	-	-	(48)
End of 2018	1,233	703	1,936	4	246	159	188	2,533
Equity affiliates								
End of 2015	-	-	-	-	-	93	-	93
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	88	-	88

Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	83	-	83
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	78	-	78
Total company								
End of 2015	915	588	1,503	14	346	296	204	2,363
End of 2016	837	506	1,343	13	303	273	203	2,135
End of 2017	937	707	1,644	1	296	268	196	2,405
End of 2018	1,233	703	1,936	4	246	237	188	2,611

Table of Contents

Years Ended December 31	Crude Oil Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed								
Consolidated operations								
End of 2015	819	283	1,102	13	200	139	204	1,658
End of 2016	747	256	1,003	13	184	106	203	1,509
End of 2017	828	315	1,143	1	190	121	196	1,651
End of 2018	1,058	346	1,404	2	192	113	185	1,896
Equity affiliates								
End of 2015	-	-	-	-	-	93	-	93
End of 2016	-	-	-	-	-	88	-	88
End of 2017	-	-	-	-	-	83	-	83
End of 2018	-	-	-	-	-	78	-	78
Undeveloped								
Consolidated operations								
End of 2015	96	305	401	1	146	64	-	612
End of 2016	90	250	340	-	119	79	-	538
End of 2017	109	392	501	-	106	64	-	671
End of 2018	175	357	532	2	54	46	3	637
Equity affiliates								
End of 2015	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2018, included:

Revisions: In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to development timing were partially offset by higher prices. Revisions in Alaska, Europe and Asia Pacific/Middle East were primarily due to higher prices. In 2017, revisions in Alaska, Lower 48, Europe and Asia Pacific/Middle East were primarily due to higher prices. In 2016, revisions in Lower 48 and Alaska were primarily due to lower prices.

Purchases: In 2018, Alaska purchases were due to the Kuparuk Assets and Western North Slope acquisitions.

Extensions and discoveries: In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays. Extensions and discoveries in Alaska were driven by drilling success in Western North Slope. In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken. In 2016, extensions and discoveries in Alaska were primarily due to drilling success in the Western North Slope, and extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

Sales: In 2018, Europe sales were due to the disposition of a subsidiary that held a 16.5 percent interest in the Clair Field in the United Kingdom. In 2017, Canada sales were due to the disposition of a majority of our western Canada assets.

Table of Contents

Years Ended December 31	Natural Gas Liquids Millions of Barrels						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Total
Developed and Undeveloped							
Consolidated operations							
End of 2015	114	321	435	45	20	8	508
Revisions	(3)	(29)	(32)	9	2	-	(21)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	18	18	2	-	-	20
Production	(4)	(32)	(36)	(8)	(3)	(3)	(50)
Sales	-	-	-	-	-	-	-
End of 2016	107	278	385	48	19	5	457
Revisions	4	29	33	-	2	1	36
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	71	71	-	-	1	72
Production	(5)	(24)	(29)	(3)	(3)	(2)	(37)
Sales	-	(130)	(130)	(44)	-	-	(174)
End of 2017	106	224	330	1	18	5	354
Revisions	5	(25)	(20)	-	1	(1)	(20)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	69	69	-	1	-	70
Production	(5)	(25)	(30)	-	(3)	(1)	(34)
Sales	-	(21)	(21)	-	-	-	(21)
End of 2018	106	222	328	1	17	3	349
Equity affiliates							
End of 2015	-	-	-	-	-	50	50
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	47	47
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(2)	(2)

Sales	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	45	45
Revisions	-	-	-	-			