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

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 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.)

600 North Dairy Ashford, Houston, TX 77079
(Address of principal executive offices) (Zip Code)

281-293-1000
(Registrant's telephone number, including area code)

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. 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). Yes ☒ No ☐

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

Large accelerated filer	☒	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 Exchange Act). Yes ☐ No ☒

The registrant had 1,151,241,888 shares of common stock, $.01 par value, outstanding at September 30, 2018.

CONOCOPHILLIPS

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PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Consolidated Income Statement **ConocoPhillips**

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017*	**2018**	2017*
Revenues and Other Income				
Sales and other operating revenues	$ **9,449**	6,688	**26,751**	20,987
Equity in earnings of affiliates	**294**	196	**767**	574
Gain on dispositions	**113**	246	**175**	2,144
Other income	**309**	65	**673**	143
Total Revenues and Other Income	**10,165**	7,195	**28,366**	23,848
Costs and Expenses				
Purchased commodities	**3,530**	2,926	**10,308**	9,040
Production and operating expenses	**1,367**	1,222	**3,851**	3,838
Selling, general and administrative expenses	**119**	110	**336**	302
Exploration expenses	**103**	73	**267**	720
Depreciation, depletion and amortization	**1,494**	1,608	**4,344**	5,212
Impairments	**44**	6	**21**	6,475
Taxes other than income taxes	**312**	175	**768**	604
Accretion on discounted liabilities	**89**	89	**266**	276
Interest and debt expense	**186**	251	**547**	872
Foreign currency transaction losses	**5**	5	**7**	28
Other expenses	**10**	77	**350**	421
Total Costs and Expenses	**7,259**	6,542	**21,065**	27,788
Income (loss) before income taxes	**2,906**	653	**7,301**	(3,940)
Income tax provision (benefit)	**1,033**	217	**2,874**	(1,549)
Net income (loss)	**1,873**	436	**4,427**	(2,391)
Less: net income attributable to noncontrolling interests	**(12)**	(16)	**(38)**	(43)
Net Income (Loss) Attributable to ConocoPhillips	$ **1,861**	420	**4,389**	(2,434)
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic	$ **1.60**	0.35	**3.74**	(1.98)
Diluted	**1.59**	0.34	**3.72**	(1.98)
Dividends Paid Per Share of Common Stock *(dollars)*	$ **0.29**	0.27	**0.86**	0.80
Average Common Shares Outstanding *(in thousands)*				
Basic	**1,163,033**	1,212,454	**1,171,673**	1,230,742
Diluted	**1,172,694**	1,215,341	**1,180,774**	1,230,742

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

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income **ConocoPhillips**

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Income (Loss)	**$ 1,873**	436	**4,427**	(2,391)
Other comprehensive income				
Defined benefit plans				
Reclassification adjustment for amortization of prior service credit included in net income (loss)	**(10)**	(9)	**(30)**	(28)
Net actuarial gain (loss) arising during the period	**187**	13	**145**	(26)
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)	**33**	49	**228**	205
Nonsponsored plans*	**—**	—	**(1)**	—
Income taxes on defined benefit plans	**(74)**	(18)	**(102)**	(52)
Defined benefit plans, net of tax	**136**	35	**240**	99
Unrealized holding gain on securities	**—**	551	**—**	127
Income taxes on unrealized holding gain on securities	**—**	(45)	**—**	(45)
Unrealized holding gain on securities, net of tax**	**—**	506	**—**	82
Foreign currency translation adjustments	**59**	509	**(222)**	720
Foreign currency translation adjustments, net of tax	**59**	509	**(222)**	720
Other Comprehensive Income, Net of Tax	**195**	1,050	**18**	901
Comprehensive Income (Loss)	**2,068**	1,486	**4,445**	(1,490)
Less: comprehensive income attributable to noncontrolling interests	**(12)**	(16)	**(38)**	(43)
Comprehensive Income (Loss) Attributable to ConocoPhillips	**$ 2,056**	1,470	**4,407**	(1,533)

**Plans for which ConocoPhillips is not the primary obligor, primarily those administered by equity affiliates.*
***See Note 2—Changes in Accounting Principles and Note 16—Accumulated Other Comprehensive Loss for additional information relating to the adoption of ASU No. 2016-01.*
See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

	Millions of Dollars	
	September 30 2018	December 31 2017
Assets		
Cash and cash equivalents	**$ 3,716**	6,325
Short-term investments	**875**	1,873
Accounts and notes receivable (net of allowance of $11 million in 2018 and $4 million in 2017)	**4,319**	4,179
Accounts and notes receivable—related parties	**180**	141
Investment in Cenovus Energy	**2,086**	1,899
Inventories	**1,239**	1,060
Prepaid expenses and other current assets	**2,308**	1,035
Total Current Assets	**14,723**	16,512
Investments and long-term receivables	**9,553**	9,599
Loans and advances—related parties	**335**	461
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $66,664 million in 2018 and $64,748 million in 2017)	**44,736**	45,683
Other assets	**1,209**	1,107
Total Assets	**$ 70,556**	73,362
Liabilities		
Accounts payable	**$ 3,887**	4,009
Accounts payable—related parties	**31**	21
Short-term debt	**95**	2,575
Accrued income and other taxes	**1,582**	1,038
Employee benefit obligations	**626**	725
Other accruals	**1,180**	1,029
Total Current Liabilities	**7,401**	9,397
Long-term debt	**14,902**	17,128
Asset retirement obligations and accrued environmental costs	**7,554**	7,631
Deferred income taxes	**5,535**	5,282
Employee benefit obligations	**1,755**	1,854
Other liabilities and deferred credits	**1,330**	1,269
Total Liabilities	**38,477**	42,561
Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2018—1,790,924,215 shares; 2017—1,785,419,175 shares)		
Par value	**18**	18
Capital in excess of par	**46,858**	46,622
Treasury stock (at cost: 2018—639,682,327 shares; 2017—608,312,034 shares)	**(41,979)**	(39,906)
Accumulated other comprehensive loss	**(5,442)**	(5,518)
Retained earnings	**32,495**	29,391
Total Common Stockholders' Equity	**31,950**	30,607
Noncontrolling interests	**129**	194
Total Equity	**32,079**	30,801
Total Liabilities and Equity	**$ 70,556**	73,362

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars	
	Nine Months Ended September 30	
	2018	2017
Cash Flows From Operating Activities		
Net income (loss)	$ **4,427**	(2,391)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation, depletion and amortization	**4,344**	5,212
Impairments	**21**	6,475
Dry hole costs and leasehold impairments	**64**	435
Accretion on discounted liabilities	**266**	276
Deferred taxes	**398**	(2,770)
Undistributed equity earnings	**(11)**	(193)
Gain on dispositions	**(175)**	(2,144)
Other	**(223)**	(367)
Working capital adjustments		
Decrease (increase) in accounts and notes receivable	**(147)**	65
Increase in inventories	**(165)**	(15)
Increase in prepaid expenses and other current assets	**(51)**	(12)
Decrease in accounts payable	**(43)**	(212)
Increase in taxes and other accruals	**446**	237
Net Cash Provided by Operating Activities	**9,151**	4,596
Cash Flows From Investing Activities		
Capital expenditures and investments	**(5,133)**	(3,074)
Working capital changes associated with investing activities	**(57)**	(18)
Proceeds from asset dispositions	**394**	13,740
Net sales (purchases) of short-term investments	**996**	(2,583)
Collection of advances/loans—related parties	**119**	115
Other	**16**	51
Net Cash Provided by (Used in) Investing Activities	**(3,665)**	8,231
Cash Flows From Financing Activities		
Repayment of debt	**(4,970)**	(6,594)
Issuance of company common stock	**121**	(65)
Repurchase of company common stock	**(2,073)**	(2,045)
Dividends paid	**(1,009)**	(986)
Other	**(111)**	(80)
Net Cash Used in Financing Activities	**(8,042)**	(9,770)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	**(40)**	244
Net Change in Cash, Cash Equivalents and Restricted Cash	**(2,596)**	3,301
Cash, cash equivalents and restricted cash at beginning of period	**6,536***	3,610
Cash, Cash Equivalents and Restricted Cash at End of Period	$ **3,940**	6,911

**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 $224 million is included in the "Other assets" line of our Consolidated Balance Sheet as of September 30, 2018.*
See Notes to Consolidated Financial Statements.

Note 1—Basis of Presentation

The interim-period financial information presented in the financial statements included in this report is unaudited and, in the opinion of management, includes all known accruals and adjustments necessary for a fair presentation of the consolidated financial position of ConocoPhillips and its results of operations and cash flows for such periods. All such adjustments are of a normal and recurring nature unless otherwise disclosed. Certain notes and other information have been condensed or omitted from the interim financial statements included in this report. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and notes included in our 2017 Annual Report on Form 10-K.

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 20—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 available-for-sale securities in other comprehensive income and instead must recognize them in the income statement. See Note 7—Investment in Cenovus Energy and Note 16—Accumulated Other Comprehensive Loss for additional information relating to this ASU.

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 20—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 properties, plants, and equipment (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
Three Months Ended September 30, 2017			
Production and operating expenses	**$ 1,224**	(2)	1,222
Selling, general and administrative expenses	**132**	(22)	110
Exploration expenses	**75**	(2)	73
Other expenses	**51**	26	77
Nine Months Ended September 30, 2017			
Production and operating expenses	**$ 3,849**	(11)	3,838
Selling, general and administrative expenses	**423**	(121)	302
Exploration expenses	**724**	(4)	720
Other expenses	**285**	136	421

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 liquefied natural gas (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 September 30, 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 September 30, 2018, the carrying value of our equity method investment in MWCC was $132 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 consisted of the following:

		Millions of Dollars	
		September 30 2018	December 31 2017
Crude oil and natural gas	$	**673**	512
Materials and supplies		**566**	548
	$	**1,239**	1,060

Inventories valued on the last-in, first-out (LIFO) basis totaled $283 million and $341 million at September 30, 2018 and December 31, 2017, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was $100 million and $124 million at September 30, 2018 and December 31, 2017, respectively.

As of September 30, 2018, crude oil and natural gas inventory includes $139 million of inventory received as part of a settlement agreement reached with Petróleos de Venezuela, S.A. (PDVSA) under an International Chamber of Commerce arbitration award. As of the end of October 2018, substantially all of the inventory recognized during the third quarter related to this settlement has been sold. For information about the settlement, see Note 13—Contingencies and Commitments.

Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions

Assets Held for Sale and Other Planned Acquisitions

In the second quarter of 2017, we signed a definitive agreement to sell our interests in the Barnett, and the assets met the asset held for sale criteria. As of September 30, 2017, we had recorded before-tax impairments of $568 million to reduce our carrying value of these assets to fair value. The agreement was terminated in the fourth quarter of 2017, and we continued to market the asset in 2018. In the first quarter of 2018, we recorded a before-tax impairment of $44 million to reduce the net carrying value to fair value of $250 million based on information gathered during marketing efforts. Marketing efforts ceased in April 2018, and the assets were reclassified as held for use in the second quarter of 2018. In the third quarter of 2018, we signed a definitive agreement to sell our interest in the Barnett to Lime Rock Resources for approximately $230 million, subject to customary adjustments. The transaction is expected to close by year-end 2018. In the third quarter of 2018, we recorded a before-tax impairment of $43 million to reduce the carrying value to fair value less costs to sell. As of September 30, 2018, our Barnett asset had a net carrying value of $201 million and was considered held for sale resulting in the reclassification of $250 million of PP&E to “Prepaid expenses and other current assets” and $49 million of noncurrent liabilities, primarily ARO, to “Other accruals” on our consolidated balance sheet. The before-tax loss associated with our interests in the Barnett, including the impairments noted above, was $59 million and $575 million for the nine-month periods of 2018 and 2017, respectively. The Barnett results of operations are reported in our Lower 48 segment.

In July 2018, we entered into an agreement to sell a ConocoPhillips subsidiary to BP. The subsidiary will hold a 16.5 percent interest in the BP-operated Clair Field in the United Kingdom and we will retain a 7.5 percent interest in the field. At the same time, we entered into an agreement with BP to acquire their 39.2 percent nonoperated interest in the Greater Kuparuk Area in Alaska, including their 38 percent interest in the Kuparuk Transportation Company (Kuparuk Assets). Both transactions are subject to regulatory approvals and are expected to close simultaneously in late 2018. Excluding customary adjustments, the transactions are expected to be cash neutral. Depending on the timing of regulatory approvals, we anticipate recognizing a noncash gain between $0.5 billion to $1.0 billion on completion of the sale of the ConocoPhillips subsidiary holding 16.5 percent of the Clair Field, after customary adjustments and foreign exchange impacts. As of September 30, 2018, our 16.5 percent interest in the Clair Field had a net carrying value of approximately $945 million consisting primarily of $1.552 billion of PP&E, $544 million of deferred tax liabilities, and $63 million of ARO. As of September 30, 2018, our 16.5 percent interest in the Clair Field was considered held for sale resulting in the reclassification of the $1.552 billion of PP&E to “Prepaid expenses and other current assets” and $63 million of ARO to “Other accruals” on our consolidated balance sheet. The before-tax earnings associated with our 16.5 percent interest in the Clair Field was $13 million and $1 million for the nine months ended September 30, 2018 and 2017, 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.

Asset Dispositions
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. No gain or loss was recognized on the sale. In September 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 before-tax gain which is reflected as “Gain on dispositions” in our consolidated income statement. In the first nine months of 2018, we completed several other dispositions.

In the second quarter of 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 included a five-year uncapped contingent payment. The contingent payment, calculated on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select quarterly average crude price exceeds $52 CAD per barrel. Contingent payments received during the five-year period will be reflected as “Gain on dispositions” in our consolidated income statement. In 2018, we recorded gains on dispositions for these contingent payments of $50 million in the second quarter and $45 million in the third quarter.

In the third quarter of 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 is effective beginning January 1, 2018, and 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. The San Juan Basin results of operations were reported within our Lower 48 segment.

Acquisition
In the second quarter of 2018, we obtained regulatory approvals for the agreement 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 Pipeline. The transaction was completed in May 2018 for $386 million, after customary adjustments. These assets are included in our Alaska segment.

Other Planned Disposition
On October 1, 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 Council of Ministers and National Parliament, as well as regulatory approvals and partner pre-emption rights. We expect it to close in early 2019. These assets are included in our Asia Pacific and Middle East segment.

Note 6—Investments, Loans and Long-Term Receivables

APLNG
APLNG's $8.5 billion project finance facility consists of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. All amounts have been drawn from the facility. APLNG made its first principal and interest payment in March 2017 and will continue 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 was successful in obtaining a United States Private Placement (USPP) bond facility of $1.4 billion. Interest payments will commence in March 2019 and principal payments in September 2023, with bi-annual payments due on the facility until September 2030. At September 30, 2018, a balance of $7.2 billion was outstanding on the facilities. See Note 12—Guarantees, for additional information.

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

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

At September 30, 2018, the carrying value of our equity method investment in APLNG was $7,676 million. The balance is included in the "Investments and long-term receivables" line on our consolidated balance sheet.

Distributions from APLNG commenced in April 2018.

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. For additional information on the Canada disposition and our investment in Cenovus Energy, see Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions and Note 7—Investment in Cenovus Energy.

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 made to certain affiliated and non-affiliated companies. At September 30, 2018, significant loans to affiliated companies included $461 million in project financing to Qatar Liquefied Gas Company Limited (3) (QG3).

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

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, Dispositions, Acquisitions and Other Planned Transactions 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 16—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.

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 $2.09 billion as of September 30, 2018, reflecting the closing price of Cenovus Energy shares on the New York Stock Exchange of $10.03 per share, an increase from its fair value of $1.90 billion at year-end 2017. For the three- and nine-month periods ended September 30, 2018, we recorded a before-tax unrealized loss of $73 million and a before-tax unrealized gain of $187 million, respectively, 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

The capitalized cost of suspended wells at September 30, 2018, was $986 million, an increase of $133 million from $853 million at year-end 2017. Three suspended wells totaling $7 million were charged to dry hole expense during the first nine months of 2018 relating to exploratory well costs capitalized for a period greater than one year as of December 31, 2017.

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Note 9—Impairments

During the three- and nine-month periods ended September 30, 2018 and 2017, we recognized before-tax impairment charges within the following segments:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Alaska	$ **—**	1	**—**	178
Lower 48	**44**	3	**55**	3,888
Canada	**—**	—	**—**	18
Europe and North Africa	**—**	2	**(48)**	7
Asia Pacific and Middle East	**—**	—	**14**	2,384
	$ **44**	6	**21**	6,475

In the three-month period ended September 30, 2018, impairments in our Lower 48 segment were primarily related to developed properties in our Barnett asset which were written down to fair value less costs to sell.

In the nine-month period ended September 30, 2018, our Lower 48 segment included before-tax impairments of $55 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 $49 million, primarily due to decreased ARO estimates on a certain field in the United Kingdom that has ceased production and was impaired in a prior year.

For additional information related to the status of our Barnett asset, see Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions.

In the nine-month period ended September 30, 2017, our Lower 48 segment included before-tax impairments of $3.3 billion for our interests in the San Juan Basin and $0.6 billion for our interests in the Barnett asset, which were written down to fair value less costs to sell. See the “APLNG” section of Note 6—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment. Additionally, our Alaska segment included an impairment of $174 million for the associated carrying value of our small interest in the Point Thomson Unit.

The charge discussed below is included in the “Exploration expenses” line on our consolidated income statement and is not reflected in the table above.

In the nine-month period ended September 30, 2017, we recorded a before-tax impairment of $51 million in our Lower 48 segment 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.

Note 10—Debt

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 our 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 September 30, 2018 or December 31, 2017. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at September 30, 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 September 30, 2018.

In the first quarter of 2018, we redeemed or repurchased a total of $2,650 million of debt as described below:

- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.
- 2.2% Notes due 2020 with principal of $500 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).

In the second quarter of 2018, we repurchased a total of $1,800 million of debt as described below:

- 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).
- 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).

During the first six months of 2018, we incurred net premiums above book value to redeem or repurchase these debt instruments of $208 million.

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

At September 30, 2018, 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.

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Note 11—Noncontrolling Interests

Activity attributable to common stockholders' equity and noncontrolling interests for the first nine months of 2018 and 2017 was as follows:

	Millions of Dollars					
	2018			2017		
	Common Stockholders' Equity	Non-Controlling Interest	Total Equity	Common Stockholders' Equity	Non-Controlling Interest	Total Equity
Balance at January 1	**$ 30,607**	**194**	**30,801**	34,974	252	35,226
Net income (loss)	**4,389**	**38**	**4,427**	(2,434)	43	(2,391)
Dividends	**(1,009)**	**—**	**(1,009)**	(986)	—	(986)
Repurchase of company common stock	**(2,073)**	**—**	**(2,073)**	(2,045)	—	(2,045)
Distributions to noncontrolling interests	**—**	**(105)**	**(105)**	—	(84)	(84)
Changes in Accounting Principles*	**(220)**	**—**	**(220)**			
Other changes, net**	**256**	**2**	**258**	991	1	992
Balance at September 30	**$ 31,950**	**129**	**32,079**	30,500	212	30,712

**See Note 2—Changes in Accounting Principles for additional information related to ASC Topic 606.*
***Includes components of other comprehensive income, which are disclosed separately in our Consolidated Statement of Comprehensive Income.*

Note 12—Guarantees

At September 30, 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 September 30, 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 September 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 September 30, 2018, the carrying value of this guarantee was approximately $14 million. For additional information, see Note 6—Investments, Loans and Long-Term Receivables.
- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of up to 24 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $940 million ($1.58 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 September 30, 2018, was approximately $100 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at September 30, 2018, were approximately $40 million of environmental accruals for known contamination that are included in the "Asset retirement obligations and accrued environmental costs" line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 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 September 30, 2018, the carrying value of this guarantee and the associated indemnification asset were removed.

Note 13—Contingencies and Commitments

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

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.

At September 30, 2018, our balance sheet included a total environmental accrual of $170 million, compared with $180 million at December 31, 2017, for remediation activities in the United States and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years. In the future, we may be involved in additional environmental assessments, cleanups and proceedings.

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 September 30, 2018, we had performance obligations secured by letters of credit of $275 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, 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. PDVSA also recognized the ICC award as a judgment in various jurisdictions. During the third quarter of 2018, we collected from PDVSA under the settlement and recognized in other income $345 million consisting of $242 million in commodity inventory and $103 million in cash. The remainder of the initial payments is due in the fourth quarter of 2018. As of the end of October 2018, substantially all of the inventory recognized during the quarter has been sold. Per the settlement, ConocoPhillips agreed to suspend its legal enforcement actions of the ICC award, including in the Dutch Caribbean. ConocoPhillips has ensured that the settlement meets all appropriate U.S. regulatory requirements, including any applicable sanctions imposed by the U.S. against Venezuela.

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

In February 2017, an 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. Earlier this year, 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 2017 and 2018, cities, counties, and/or state governments in California, New York, Washington, Rhode Island and Maryland 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.

Note 14—Derivative and Financial Instruments

Derivative 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 (NPNS) exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

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

	Millions of Dollars	
	September 30 2018	December 31 2017
Assets		
Prepaid expenses and other current assets	$ **259**	275
Other assets	**42**	36
Liabilities		
Other accruals	**278**	282
Other liabilities and deferred credits	**37**	28

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

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Sales and other operating revenues	$ **(29)**	17	**(6)**	120
Other income	**3**	(1)	**12**	(1)
Purchased commodities	**18**	(19)	**15**	(88)

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

	Open Position Long/(Short)	
	September 30 2018	December 31 2017
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(19)**	(29)
Basis	**5**	12

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 and 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	
	September 30 2018	December 31 2017
Assets		
Prepaid expenses and other current assets	$ **18**	1
Other assets	**—**	6
Liabilities		
Other accruals	**7**	—
Other liabilities and deferred credits	**—**	15

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

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

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Foreign currency transaction (gains) losses	$ **(2)**	(1)	**(5)**	2

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

		In Millions Notional Currency	
		September 30 2018	December 31 2017
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy other currencies*	USD	**1,258**	—
Sell British pound, buy euro	GBP	**23**	1
Sell Canadian dollar, buy U.S. dollar	CAD	**1,230**	1,225

**Primarily British pound.*

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 we currently invest in include:

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.

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

	Millions of Dollars				
	Carrying Amount				
	Cash and Cash Equivalents			Short-Term Investments	
	September 30 2018		December 31 2017	**September 30 2018**	December 31 2017
Cash	$	**511**	948		
Time deposits					
Remaining maturities from 1 to 90 days		**2,966**	5,004	**104**	821
Commercial paper					
Remaining maturities from 1 to 90 days		**239**	373	**771**	978
Remaining maturities from 91 to 180 days		**—**	—	**—**	74
	$	**3,716**	6,325	**875**	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 September 30, 2018 and December 31, 2017, was $44 million and $55 million, respectively. For these instruments, no collateral was posted as of September 30, 2018 or December 31, 2017. If our credit rating had been downgraded below investment grade on September 30, 2018, we would be required to post $44 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 investment in Cenovus Energy transferred from Level 2 to Level 1 due to the lapsing of trading restrictions. There were no other material transfers between levels during 2018 or 2017.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include our investment in Cenovus Energy shares and commodity derivatives. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 1 also includes our investment in common shares of Cenovus Energy, which is valued using quotes for shares on the New York Stock Exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value. Level 3 activity was not material for all periods presented.

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

	Millions of Dollars							
	September 30, 2018				December 31, 2017			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Investment in Cenovus Energy	**$ 2,086**	**—**	**—**	**2,086**	1,899	—	—	1,899
Commodity derivatives	**186**	**97**	**18**	**301**	175	106	30	311
Total assets	**$ 2,272**	**97**	**18**	**2,387**	2,074	106	30	2,210
Liabilities								
Commodity derivatives	**$ 176**	**103**	**36**	**315**	158	111	41	310
Total liabilities	**$ 176**	**103**	**36**	**315**	158	111	41	310

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

	Millions of Dollars					
	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Gross Amounts without Right of Setoff	Net Amounts
September 30, 2018						
Assets	**$ 301**	**206**	**95**	**—**	**7**	**88**
Liabilities	**315**	**206**	**109**	**2**	**3**	**104**
December 31, 2017						
Assets	$ 311	186	125	—	4	121
Liabilities	310	186	124	7	5	112

At September 30, 2018 and December 31, 2017, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

Non-Recurring Fair Value Measurement

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

	Millions of Dollars			
		Fair Value Measurements Using		
	Fair Value	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Net PP&E (held for sale)				
March 31, 2018	**$ 250**	**—**	**250**	**44**
September 30, 2018	**$ 201**	**201**	**—**	**43**

During the first and third quarters of 2018, certain net PP&E held for sale was written down to fair value, less costs to sell. In the third quarter, fair value was determined by its negotiated selling price. In the first quarter, fair value was estimated using information gathered during marketing efforts. For additional information, see Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions.

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.

- 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	
	September 30 2018	December 31 2017	**September 30 2018**	December 31 2017
Financial assets				
Investment in Cenovus Energy	**$ 2,086**	1,899	**2,086**	1,899
Commodity derivatives	**95**	125	**95**	125
Total loans and advances—related parties	**464**	586	**464**	586
Financial liabilities				
Total debt, excluding capital leases	**14,201**	18,929	**16,554**	22,435
Commodity derivatives	**107**	117	**107**	117

Note 16—Accumulated Other Comprehensive Loss

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

	Millions of Dollars			
	Defined Benefit Plans	Net Unrealized Loss on Securities	Foreign Currency Translation	Accumulated Other Comprehensive Income (Loss)
December 31, 2017	$ (400)	(58)	(5,060)	(5,518)
Cumulative effect of adopting ASU No. 2016-01*	**—**	**58**	**—**	**58**
Other comprehensive income (loss)	**240**	**—**	**(222)**	**18**
September 30, 2018	**$ (160)**	**—**	**(5,282)**	**(5,442)**

**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:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Defined benefit plans	$ **17**	26	**155**	116

The above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of $6 million and $14 million for the three months ended September 30, 2018 and September 30, 2017, respectively, and $43 million and $61 million for the nine-month periods ended September 30, 2018 and September 30, 2017, respectively. See Note 18—Employee Benefit Plans, for additional information.

Note 17—Cash Flow Information

	Millions of Dollars	
	Nine Months Ended September 30	
	2018	2017
Cash Payments		
Interest	$ **584**	918
Income taxes	**1,927**	574
Net Sales (Purchases) of Short-Term Investments		
Short-term investments purchased	$ **(1,705)**	(4,999)
Short-term investments sold	**2,701**	2,416
	$ **996**	(2,583)

The following items are included in the "Cash Flows From Operating Activities" section of our consolidated statement of cash flows:

In the second quarter of 2018, we received a settlement payment of $262 million from the Republic of Ecuador. In the third quarter of 2018, we received a settlement payment of $103 million from PDVSA. For more information see Note 13—Contingencies and Commitments.

In the first quarter of 2017, we recognized a $180 million adverse cash impact from the settlement of cross-currency swap transactions.

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Note 18—Employee Benefit Plans

Pension and Postretirement Plans

	Millions of Dollars						
	Pension Benefits					Other Benefits	
	2018		2017			**2018**	2017
		U.S.	Int'l.	U.S.	Int'l.		
Components of Net Periodic Benefit Cost							
Three Months Ended September 30							
Service cost	$	**20**	**20**	21	20	**—**	—
Interest cost		**22**	**26**	29	27	**2**	3
Expected return on plan assets		**(22)**	**(38)**	(32)	(41)	**—**	—
Amortization of prior service cost (credit)		**—**	**(1)**	1	(1)	**(9)**	(9)
Recognized net actuarial loss (gain)		**10**	**9**	17	12	**—**	(1)
Settlements		**14**	**—**	21	—	**—**	—
Curtailments		**—**	**(1)**	—	—	**—**	—
Net periodic benefit cost	$	**44**	**15**	57	17	**(7)**	(7)
Nine Months Ended September 30							
Service cost	$	**63**	**63**	67	59	**1**	1
Interest cost		**76**	**80**	90	78	**6**	7
Expected return on plan assets		**(91)**	**(118)**	(97)	(119)	**—**	—
Amortization of prior service cost (credit)		**—**	**(4)**	3	(4)	**(26)**	(27)
Recognized net actuarial loss (gain)		**41**	**27**	53	36	**(1)**	(2)
Settlements		**161**	**—**	118	—	**—**	—
Curtailments		**—**	**(1)**	—	—	**—**	—
Net periodic benefit cost	$	**250**	**47**	234	50	**(20)**	(21)

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.

During the first nine months of 2018, we contributed $150 million to our domestic benefit plans and $130 million to our international benefit plans. In 2018, we expect to contribute approximately $160 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $160 million to our international qualified and nonqualified pension and postretirement benefit plans.

In June 2018, we purchased a group annuity contract from Prudential and transferred approximately $700 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.

We recognized a proportionate share of prior actuarial losses from other comprehensive income as pension settlement expense of $14 million and $161 million during the three- and nine-month periods ended September 30, 2018, respectively. In conjunction with the recognition of pension settlement expense, the fair market values of the U.S. qualified pension plan assets were updated, and the pension benefit obligation of the U.S. qualified pension plan was remeasured as of June 30, 2018. At the measurement date, the net pension liability increased by $42 million as a result of a loss on U.S. qualified pension plan assets, offset by a gain on the projected benefit obligation due primarily to an increase in the discount rate from 3.6 percent to 4.2 percent, resulting in a corresponding decrease to other comprehensive income.

During the three-month period ended September 30, 2018, the fair market value of certain international pension plan assets were updated, and the pension benefit obligations associated with these plans were remeasured. At the measurement date, the net pension liability decreased by $157 million with a corresponding increase to other comprehensive income primarily as a result of an increase in discount rate from 2.55 percent at December 31, 2017, to 2.95 percent at September 30, 2018. The reduction in net pension liability resulted in a balance of $146 million associated with an international qualified plan being reclassified to the "Other assets" line on our consolidated balance sheet.

Severance Accrual

As a result of staff reductions occurring throughout the year, severance accruals of $35 million and $65 million were recorded during the three- and nine-month periods ended September 30, 2018, respectively. The following table summarizes our severance accrual activity for the nine-month period ended September 30, 2018:

	Millions of Dollars
Balance at December 31, 2017	$ 53
Accruals	**65**
Benefit payments	**(38)**
Balance at September 30, 2018	**$ 80**

Of the remaining balance at September 30, 2018, $55 million is classified as short term.

Note 19—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			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Operating revenues and other income	**$ 27**	24	**74**	83
Purchases	**25**	26	**74**	74
Operating expenses and selling, general and administrative expenses	**13**	16	**44**	42
Net interest (income) expense*	**(4)**	(4)	**(11)**	(10)

**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.*

Note 20—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.

Accounting Policy

Revenues associated with the sales of crude oil, bitumen, 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.

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.

Revenue from Contracts with Customers

The following table provides further disaggregation of our consolidated sales and other operating revenues:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017*	**2018**	2017*
Revenue from contracts with customers	**$ 7,546**	4,636	**20,834**	14,428
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative	**1,897**	2,050	**5,877**	6,631
Financial derivative contracts	**6**	2	**40**	(72)
Consolidated sales and other operating revenues	**$ 9,449**	6,688	**26,751**	20,987

**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 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 21—Segment Disclosures and Related Information:

	Millions of Dollars				
	Three Months Ended September 30			Nine Months Ended September 30	
		2018	2017*	**2018**	2017*
Revenue from Outside the Scope of ASC Topic 606 by Segment					
Lower 48	$	**1,534**	1,563	**4,547**	4,834
Canada		**87**	161	**374**	680
Europe and North Africa		**276**	326	**956**	1,117
Physical contracts meeting the definition of a derivative	$	**1,897**	2,050	**5,877**	6,631

**Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.*

	Millions of Dollars				
	Three Months Ended September 30			Nine Months Ended September 30	
		2018	2017*	**2018**	2017*
Revenue from Outside the Scope of ASC Topic 606 by Product					
Crude oil	$	**267**	171	**843**	530
Natural gas		**1,522**	1,811	**4,775**	5,870
Other		**108**	68	**259**	231
Physical contracts meeting the definition of a derivative	$	**1,897**	2,050	**5,877**	6,631

**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 September 30, 2018, the "Accounts and notes receivable" line on our consolidated balance sheet included trade receivables of $3,129 million compared with $2,675 million at December 31, 2017, and included both contracts with customers within the scope of ASC Topic 606 and those that are outside the scope of ASC Topic 606. We typically receive payment within 30 days or less (depending on the terms of the invoice) once delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical gas sales contracts at market prices for which we do not elect NPNS and are therefore accounted for as a derivative under ASC Topic 815. There is little distinction in the nature of the customer or credit quality of trade receivables associated with gas sold under contracts for which NPNS has not been elected compared with trade receivables where NPNS has been elected.

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

	Millions of Dollars
Contract Liabilities	
At January 1, 2018	**$ 251**
Contractual payments received*	**81**
Revenue recognized	**(148)**
At September 30, 2018	**$ 184**
Amounts Recognized in the Consolidated Balance Sheet at September 30, 2018	
Current liabilities	**$ 147**
Noncurrent liabilities	**37**
	$ 184

**Includes $14 million and $81 million for the three- and nine-month periods of 2018, respectively.*

For the three- and nine-month periods of 2018, we recognized revenue of $73 million and $148 million, respectively, in the “Sales and other operating revenues” line on our consolidated income statement. We expect to recognize the contract liabilities as of September 30, 2018, as revenue between the remainder of 2018 and 2022 as construction is completed.

Prior to the adoption of ASC Topic 606, contractual cash payments received would have been recognized as “Sales and other operating revenues” when received.

Note 21—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, 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. Intersegment sales are at prices that approximate market.

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Analysis of Results by Operating Segment

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017*	**2018**	2017*
Sales and Other Operating Revenues				
Alaska	$ **1,493**	932	**4,281**	3,010
Lower 48	**4,543**	3,102	**12,347**	9,422
Intersegment eliminations	**(14)**	(2)	**(18)**	(7)
Lower 48	**4,529**	3,100	**12,329**	9,415
Canada	**735**	699	2,436	2,357
Intersegment eliminations	**(308)**	(155)	(853)	(330)
Canada	**427**	544	**1,583**	2,027
Europe and North Africa	**1,574**	1,110	**4,826**	3,564
Asia Pacific and Middle East	**1,348**	959	**3,570**	2,877
Corporate and Other	**78**	43	**162**	94
Consolidated sales and other operating revenues	$ **9,449**	6,688	**26,751**	20,987
Sales and Other Operating Revenues by Geographic Location				
United States	$ **6,025**	4,038	**16,617**	12,440
Australia	**515**	323	**1,258**	1,050
Canada	**427**	544	**1,583**	2,027
China	**262**	148	**616**	511
Indonesia	**234**	191	**662**	554
Libya**	**264**	91	**802**	315
Malaysia	**339**	297	**1,039**	768
Norway	**734**	583	**2,112**	1,751
United Kingdom	**574**	437	**1,911**	1,498
Other foreign countries	**75**	36	**151**	73
Worldwide consolidated	$ **9,449**	6,688	**26,751**	20,987
Sales and Other Operating Revenues by Product				
Crude Oil	$ **5,277**	2,947	**14,503**	9,387
Natural gas	**2,503**	2,496	**7,593**	7,949
Natural gas liquids	**351**	238	**847**	745
Other***	**1,318**	1,007	**3,808**	2,906
Consolidated sales and other operating revenues by product	$ **9,449**	6,688	**26,751**	20,987

Under the modified retrospective approach, prior period amounts have not been adjusted upon adoption of ASC Topic 606.
**Included in "Other foreign countries" in prior periods.*
***Includes LNG and bitumen.*

Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$ **427**	103	**1,369**	291
Lower 48	**513**	(97)	**1,231**	(2,995)
Canada	**34**	280	**2**	2,607
Europe and North Africa	**241**	85	**776**	379
Asia Pacific and Middle East	**577**	396	**1,504**	(1,540)
Other International	**316**	(20)	**267**	(77)
Corporate and Other	**(247)**	(327)	**(760)**	(1,099)
Consolidated net income (loss) attributable to ConocoPhillips	$ **1,861**	420	**4,389**	(2,434)

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	Millions of Dollars	
	September 30 2018	December 31 2017
Total Assets		
Alaska	**$ 12,688**	12,108
Lower 48	**15,308**	14,632
Canada	**5,950**	6,214
Europe and North Africa	**11,895**	11,870
Asia Pacific and Middle East	**16,611**	16,985
Other International	**315**	97
Corporate and Other	**7,789**	11,456
Consolidated total assets	**$ 70,556**	73,362

Note 22—Income Taxes

Our effective tax rates for the three- and nine-month periods ended September 30, 2018, were 36 percent and 39 percent, respectively, compared with 33 percent and 39 percent for the same periods of 2017. 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)			
	Three Months Ended September 30		Nine Months Ended September 30		Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017
Income (loss) before income taxes								
United States	**$ 893**	(197)	**2,799**	(5,259)	**30.7%**	(30.2)	**38.3**	133.5
Foreign	**2,013**	850	**4,502**	1,319	**69.3**	130.2	**61.7**	(33.5)
	$ 2,906	653	**7,301**	(3,940)	**100.0%**	100.0	**100.0**	100.0
Federal statutory income tax	**$ 610**	228	**1,533**	(1,379)	**21.0%**	35.0	**21.0**	35.0
Non-U.S. effective tax rates	**479**	137	**1,339**	503	**16.5**	21.0	**18.3**	(12.8)
Canada disposition	**—**	(8)	**—**	(1,176)	**—**	(1.2)	**—**	29.8
Recovery of outside basis	**(16)**	(118)	**(19)**	(957)	**(0.6)**	(18.1)	**(0.2)**	24.3
Adjustment to tax reserves	**(3)**	(17)	**2**	764	**(0.1)**	(2.6)	**—**	(19.4)
Adjustment to valuation allowance	**(29)**	—	**13**	24	**(1.0)**	—	**0.2**	(0.6)
APLNG impairment	**—**	—	**—**	834	**—**	—	**—**	(21.2)
State income tax	**38**	14	**83**	(98)	**1.3**	2.1	**1.1**	2.5
Enhanced oil recovery credit	**(36)**	(5)	**(73)**	(49)	**(1.3)**	(0.8)	**(1.0)**	1.2
Other	**(10)**	(14)	**(4)**	(15)	**(0.3)**	(2.2)	**—**	0.5
	$ 1,033	217	**2,874**	(1,549)	**35.5%**	33.2	**39.4**	39.3

The effective tax rate represents a blend of federal, state and foreign taxes and includes the impact of certain nondeductible items and adjustments to our valuation allowance. The effective tax rate for the three- and nine- month periods ended September 30, 2018, also reflects the reduced federal corporate income tax rate as a result of the enactment of the Tax Cuts and Jobs Act (the Tax Legislation) in December 2017 and the impact of a change in the mix of our domestic and foreign earnings.

In the third quarter of 2018, we recognized $53 million of U.S. Federal tax benefit related to previously unrecognized deferred tax assets associated with the income from the PDVSA settlement agreement. This benefit is included in the “Adjustment to Valuation Allowance” and “Recovery of Outside Basis” lines of the table above. Any future amounts received under the PDVSA settlement should result in nominal U.S. income tax implications due to the availability of unrecognized U.S. tax attributes to offset the receipts. For additional information, see Note 13—Contingencies and Commitments.

Our effective tax rate for the three- and nine-month periods ended September 30, 2017, was favorably impacted by a tax benefit of $114 million related to our prior decision to exit Nova Scotia deepwater exploration. This benefit is included in the “Recovery of Outside Tax Basis” line of the table above.

Our effective tax rate for the nine-month period ended September 30, 2017, was also favorably impacted by a tax benefit of $1,176 million, associated with our 2017 disposition of various assets in Canada. 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.

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.

We have not significantly revised the tax accounting impacts of our 2017 provisional estimates under Staff Accounting Bulletin 118 and ASU No. 2018-05, “Income Taxes” (Topic 740), but we are continuing to gather information and are waiting for further guidance from the Internal Revenue Service, Securities Exchange Commission and FASB on the Tax Legislation.

The Tax Legislation subjects a U.S. shareholder to tax on Global Intangible Low-Taxed Income (GILTI) earned by certain foreign subsidiaries. The FASB Staff Q&A, Topic 740, No. 5, “Accounting for Global Intangible Low-Taxed Income,” states that an entity can make an accounting policy election to either recognize deferred taxes for temporary basis differences expected to reverse as GILTI in future years or provide for the tax expense related to GILTI in the year the tax is incurred as a period expense only. Given the complexity, we are still evaluating the effects of the GILTI provisions and have not yet determined our accounting policy. At September 30, 2018, the current-year U.S. income tax impact related to GILTI activities is immaterial.

Note 23—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, the FASB issued ASU No. 2018-11, “Targeted Improvements” (ASU No. 2018-11), in July 2018 to set forth certain additional practical expedients for lessors and to provide 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 continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. We are currently implementing a third-party lease accounting software solution to facilitate the ongoing accounting and financial reporting requirements of the ASU. We also continue to monitor proposals issued by the FASB to clarify the ASU and certain industry implementation issues.

While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact to our consolidated financial statements. Such impact is expected to relate primarily to our balance sheet, resulting from the initial recognition of lease liabilities and corresponding right-of-use assets for our population of operating leases, as well as enhanced disclosure of our leasing arrangements. We also expect the adoption of ASU No. 2016-02 to result in certain changes being made to our existing accounting policies and systems, business processes, and internal controls.

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.

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Canada Funding Company I is an indirect, 100 percent owned subsidiary of ConocoPhillips Company. ConocoPhillips and/or ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Canada Funding Company I, with respect to its publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

In March 2018, ConocoPhillips Company received a $1.2 billion loan repayment from a nonguarantor subsidiary to settle certain accumulated intercompany balances. This transaction had no impact on our consolidated financial statements.

In June 2018, ConocoPhillips received a $2.5 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In the second quarter of 2018, ConocoPhillips Company received $1.2 billion of loan repayments from a nonguarantor subsidiary to settle certain accumulated intercompany balances. This transaction had no impact on our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

Income Statement	Millions of Dollars Three Months Ended September 30, 2018 ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$ —	4,330	—	5,119	—	9,449
Equity in earnings of affiliates	1,903	2,166	—	256	(4,031)	294
Gain on dispositions	—	75	—	38	—	113
Other income	—	(61)	—	370	—	309
Intercompany revenues	9	34	42	1,619	(1,704)	—
Total Revenues and Other Income	1,912	6,544	42	7,402	(5,735)	10,165
Costs and Expenses						
Purchased commodities	—	3,880	—	1,196	(1,546)	3,530
Production and operating expenses	—	298	—	1,085	(16)	1,367
Selling, general and administrative expenses	2	99	—	18	—	119
Exploration expenses	—	41	—	62	—	103
Depreciation, depletion and amortization	—	152	—	1,342	—	1,494
Impairments	—	1	—	43	—	44
Taxes other than income taxes	—	33	—	279	—	312
Accretion on discounted liabilities	—	4	—	85	—	89
Interest and debt expense	72	156	37	63	(142)	186
Foreign currency transaction (gains) losses	(12)	3	42	(28)	—	5
Other expenses	—	6	—	4	—	10
Total Costs and Expenses	62	4,673	79	4,149	(1,704)	7,259
Income (Loss) before income taxes	1,850	1,871	(37)	3,253	(4,031)	2,906
Income tax provision (benefit)	(11)	(32)	1	1,075	—	1,033
Net income (loss)	1,861	1,903	(38)	2,178	(4,031)	1,873
Less: net income attributable to noncontrolling interests	—	—	—	(12)	—	(12)
Net Income (Loss) Attributable to ConocoPhillips	$ 1,861	1,903	(38)	2,166	(4,031)	1,861
Comprehensive Income Attributable to ConocoPhillips	$ 2,056	2,098	5	2,330	(4,433)	2,056

Income Statement	Three Months Ended September 30, 2017*					
Revenues and Other Income						
Sales and other operating revenues	$ —	2,997	—	3,691	—	6,688
Equity in earnings of affiliates	486	348	—	119	(757)	196
Gain (Loss) on dispositions	—	879	—	(633)	—	246
Other income	—	12	—	53	—	65
Intercompany revenues	10	77	43	774	(904)	—
Total Revenues and Other Income	496	4,313	43	4,004	(1,661)	7,195
Costs and Expenses						
Purchased commodities	—	2,666	—	1,001	(741)	2,926
Production and operating expenses	—	216	—	1,007	(1)	1,222
Selling, general and administrative expenses	2	97	—	11	—	110
Exploration expenses	—	29	—	44	—	73
Depreciation, depletion and amortization	—	203	—	1,405	—	1,608
Impairments	—	1	—	5	—	6
Taxes other than income taxes	—	29	—	146	—	175
Accretion on discounted liabilities	—	8	—	81	—	89
Interest and debt expense	86	169	37	121	(162)	251
Foreign currency transaction (gains) losses	(27)	1	77	(46)	—	5
Other expenses	50	29	—	(2)	—	77
Total Costs and Expenses	111	3,448	114	3,773	(904)	6,542
Income (Loss) before income taxes	385	865	(71)	231	(757)	653
Income tax provision (benefit)	(35)	379	6	(133)	—	217
Net income (loss)	420	486	(77)	364	(757)	436
Less: net income attributable to noncontrolling interests	—	—	—	(16)	—	(16)
Net Income (Loss) Attributable to ConocoPhillips	$ 420	486	(77)	348	(757)	420
Comprehensive Income Attributable to ConocoPhillips	$ 1,470	1,536	22	864	(2,422)	1,470

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

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Income Statement	Millions of Dollars					
	Nine Months Ended September 30, 2018					
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$ —	11,774	—	14,977	—	26,751
Equity in earnings of affiliates	4,562	5,398	—	833	(10,026)	767
Gain on dispositions	—	78	—	97	—	175
Other income	—	230	—	443	—	673
Intercompany revenues	28	124	129	4,227	(4,508)	—
Total Revenues and Other Income	4,590	17,604	129	20,577	(14,534)	28,366
Costs and Expenses						
Purchased commodities	—	10,571	—	3,757	(4,020)	10,308
Production and operating expenses	—	723	—	3,181	(53)	3,851
Selling, general and administrative expenses	7	254	—	80	(5)	336
Exploration expenses	—	132	—	135	—	267
Depreciation, depletion and amortization	—	427	—	3,917	—	4,344
Impairments	—	(9)	—	30	—	21
Taxes other than income taxes	—	111	—	657	—	768
Accretion on discounted liabilities	—	13	—	253	—	266
Interest and debt expense	219	456	110	192	(430)	547
Foreign currency transaction (gains) losses	22	(6)	(43)	34	—	7
Other expenses	—	348	—	2	—	350
Total Costs and Expenses	248	13,020	67	12,238	(4,508)	21,065
Income before income taxes	4,342	4,584	62	8,236	(10,026)	7,301
Income tax provision (benefit)	(47)	22	(5)	2,904	—	2,874
Net income	4,389	4,562	67	5,332	(10,026)	4,427
Less: net income attributable to noncontrolling interests	—	—	—	(38)	—	(38)
Net Income Attributable to ConocoPhillips	$ 4,389	4,562	67	5,294	(10,026)	4,389
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ 4,407	4,580	(13)	5,186	(9,856)	4,407

Income Statement	Nine Months Ended September 30, 2017*					
Revenues and Other Income						
Sales and other operating revenues	$ —	9,066	—	11,921	—	20,987
Equity in earnings (losses) of affiliates	(2,092)	(776)	—	432	3,010	574
Gain on dispositions	—	908	—	1,236	—	2,144
Other income	1	27	—	115	—	143
Intercompany revenues	39	222	126	2,360	(2,747)	—
Total Revenues and Other Income	(2,052)	9,447	126	16,064	263	23,848
Costs and Expenses						
Purchased commodities	—	8,068	—	3,229	(2,257)	9,040
Production and operating expenses	—	483	—	3,358	(3)	3,838
Selling, general and administrative expenses	8	244	—	55	(5)	302
Exploration expenses	—	433	—	287	—	720
Depreciation, depletion and amortization	—	658	—	4,554	—	5,212
Impairments	—	1,075	—	5,400	—	6,475
Taxes other than income taxes	—	114	—	490	—	604
Accretion on discounted liabilities	—	28	—	248	—	276
Interest and debt expense	340	505	110	399	(482)	872
Foreign currency transaction (gains) losses	(49)	3	145	(71)	—	28
Other expenses	267	159	—	(5)	—	421
Total Costs and Expenses	566	11,770	255	17,944	(2,747)	27,788
Loss before income taxes	(2,618)	(2,323)	(129)	(1,880)	3,010	(3,940)
Income tax provision (benefit)	(184)	(231)	12	(1,146)	—	(1,549)
Net loss	(2,434)	(2,092)	(141)	(734)	3,010	(2,391)
Less: net income attributable to noncontrolling interests	—	—	—	(43)	—	(43)
Net Loss Attributable to ConocoPhillips	$ (2,434)	(2,092)	(141)	(777)	3,010	(2,434)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ (1,533)	(1,191)	39	(37)	1,189	(1,533)

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

Balance Sheet	Millions of Dollars September 30, 2018 ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ —	16	—	3,700	—	3,716
Short-term investments	—	—	—	875	—	875
Accounts and notes receivable	6	2,614	1	5,301	(3,423)	4,499
Investment in Cenovus Energy	—	2,086	—	—	—	2,086
Inventories	—	198	—	1,041	—	1,239
Prepaid expenses and other current assets	—	159	7	2,169	(27)	2,308
Total Current Assets	6	5,073	8	13,086	(3,450)	14,723
Investments, loans and long-term receivables*	31,249	51,482	2,623	20,829	(96,295)	9,888
Net properties, plants and equipment	—	4,495	—	40,709	(468)	44,736
Other assets	19	484	178	1,458	(930)	1,209
Total Assets	$ 31,274	61,534	2,809	76,082	(101,143)	70,556
Liabilities and Stockholders' Equity						
Accounts payable	$ —	3,444	7	3,890	(3,423)	3,918
Short-term debt	(3)	12	7	88	(9)	95
Accrued income and other taxes	—	104	—	1,478	—	1,582
Employee benefit obligations	—	476	—	150	—	626
Other accruals	57	404	51	695	(27)	1,180
Total Current Liabilities	54	4,440	65	6,301	(3,459)	7,401
Long-term debt	3,790	7,152	1,698	2,740	(478)	14,902
Asset retirement obligations and accrued environmental costs	—	424	—	7,130	—	7,554
Deferred income taxes	—	—	—	5,968	(433)	5,535
Employee benefit obligations	—	1,315	—	440	—	1,755
Other liabilities and deferred credits*	2,042	11,064	981	7,643	(20,400)	1,330
Total Liabilities	5,886	24,395	2,744	30,222	(24,770)	38,477
Retained earnings	25,972	17,591	(614)	16,906	(27,360)	32,495
Other common stockholders' equity	(584)	19,548	679	28,825	(49,013)	(545)
Noncontrolling interests	—	—	—	129	—	129
Total Liabilities and Stockholders' Equity	$ 31,274	61,534	2,809	76,082	(101,143)	70,556

**Includes intercompany loans.*

Balance Sheet	December 31, 2017					
Assets						
Cash and cash equivalents	$ —	234	4	6,087	—	6,325
Short-term investments	—	—	—	1,873	—	1,873
Accounts and notes receivable	24	2,255	35	4,870	(2,864)	4,320
Investment in Cenovus Energy	—	1,899	—	—	—	1,899
Inventories	—	163	—	897	—	1,060
Prepaid expenses and other current assets	1	278	6	779	(29)	1,035
Total Current Assets	25	4,829	45	14,506	(2,893)	16,512
Investments, loans and long-term receivables*	29,400	47,974	2,533	15,050	(84,897)	10,060
Net properties, plants and equipment	—	4,230	—	41,930	(477)	45,683
Other assets	15	1,146	186	1,302	(1,542)	1,107
Total Assets	$ 29,440	58,179	2,764	72,788	(89,809)	73,362
Liabilities and Stockholders' Equity						
Accounts payable	$ —	3,094	1	3,799	(2,864)	4,030
Short-term debt	(5)	2,505	7	77	(9)	2,575
Accrued income and other taxes	—	107	—	931	—	1,038
Employee benefit obligations	—	554	—	171	—	725
Other accruals	85	314	48	612	(30)	1,029
Total Current Liabilities	80	6,574	56	5,590	(2,903)	9,397
Long-term debt	3,787	9,321	1,703	2,794	(477)	17,128
Asset retirement obligations and accrued environmental costs	—	432	—	7,199	—	7,631
Deferred income taxes	—	—	—	6,263	(981)	5,282
Employee benefit obligations	—	1,335	—	519	—	1,854
Other liabilities and deferred credits*	1,528	5,229	926	9,215	(15,629)	1,269
Total Liabilities	5,395	22,891	2,685	31,580	(19,990)	42,561
Retained earnings	22,867	13,317	(681)	11,958	(18,070)	29,391
Other common stockholders' equity	1,178	21,971	760	29,056	(51,749)	1,216
Noncontrolling interests	—	—	—	194	—	194
Total Liabilities and Stockholders' Equity	$ 29,440	58,179	2,764	72,788	(89,809)	73,362

**Includes intercompany loans.*

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Statement of Cash Flows	Millions of Dollars					
	Nine Months Ended September 30, 2018					
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ 2,331	863	(121)	8,937	(2,859)	9,151
Cash Flows From Investing Activities						
Capital expenditures and investments	—	(771)	—	(4,369)	7	(5,133)
Working capital changes associated with investing activities	—	(77)	—	20	—	(57)
Proceeds from asset dispositions	—	307	—	199	(112)	394
Sales of short-term investments	—	—	—	996	—	996
Long-term advances/loans—related parties	—	(36)	—	(127)	163	—
Collection of advances/loans—related parties	—	3,432	—	129	(3,442)	119
Intercompany cash management	514	3,426	—	(3,940)	—	—
Other	—	—	—	16	—	16
Net Cash Provided by (Used in) Investing Activities	514	6,281	—	(7,076)	(3,384)	(3,665)
Cash Flows From Financing Activities						
Issuance of debt	—	10	117	36	(163)	—
Repayment of debt	—	(4,865)	—	(3,547)	3,442	(4,970)
Issuance of company common stock	234	—	—	—	(113)	121
Repurchase of company common stock	(2,073)	—	—	—	—	(2,073)
Dividends paid	(1,009)	—	—	(452)	452	(1,009)
Other	3	(2,511)	—	(228)	2,625	(111)
Net Cash Provided by (Used in) Financing Activities	(2,845)	(7,366)	117	(4,191)	6,243	(8,042)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	—	4	—	(44)	—	(40)
Net Change in Cash, Cash Equivalents and Restricted Cash	—	(218)	(4)	(2,374)	—	(2,596)
Cash, cash equivalents and restricted cash at beginning of period*	—	234	4	6,298	—	6,536
Cash, Cash Equivalents and Restricted Cash at End of Period	$ —	16	—	3,924	—	3,940

Statement of Cash Flows	Nine Months Ended September 30, 2017					
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ (161)	634	22	6,868	(2,767)	4,596
Cash Flows From Investing Activities						
Capital expenditures and investments	—	(1,230)	—	(2,711)	867	(3,074)
Working capital changes associated with investing activities	—	36	—	(54)	—	(18)
Proceeds from asset dispositions	5,000	10,974	—	12,737	(14,971)	13,740
Purchases of short-term investments	—	—	—	(2,583)	—	(2,583)
Long-term advances/loans—related parties	—	(74)	—	(20)	94	—
Collection of advances/loans—related parties	658	127	—	2,196	(2,866)	115
Intercompany cash management	2,903	(2,474)	—	(429)	—	—
Other	—	—	—	51	—	51
Net Cash Provided by Investing Activities	8,561	7,359	—	9,187	(16,876)	8,231
Cash Flows From Financing Activities						
Issuance of debt	—	20	—	74	(94)	—
Repayment of debt	(5,459)	(3,146)	—	(855)	2,866	(6,594)
Issuance of company common stock	87	—	—	—	(152)	(65)
Repurchase of company common stock	(2,045)	—	—	—	—	(2,045)
Dividends paid	(986)	—	—	(2,919)	2,919	(986)
Other	3	(5,000)	—	(9,187)	14,104	(80)
Net Cash Used in Financing Activities	(8,400)	(8,126)	—	(12,887)	19,643	(9,770)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	1	—	243	—	244
Net Change in Cash and Cash Equivalents	—	(132)	22	3,411	—	3,301
Cash and cash equivalents at beginning of period	—	358	13	3,239	—	3,610
Cash and Cash Equivalents at End of Period	$ —	226	35	6,650	—	6,911

**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 $224 million is included in the "Other assets" line of our Consolidated Balance Sheet as of September 30, 2018.*

Item 2. 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. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "should," "will," "would," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 64.

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. Our diverse portfolio primarily includes resource-rich North American unconventional assets and oil sands assets in Canada; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects. Headquartered in Houston, Texas, we had operations and activities in 17 countries, approximately 11,100 employees worldwide and total assets of $71 billion as of September 30, 2018.

Overview

While global crude oil prices continued to improve in the third quarter of 2018, our business strategy anticipates prices will remain cyclical. 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; reduce debt to a level we believe is sufficient to maintain a strong investment grade rating through price cycles; repurchase shares to provide value to our shareholders; and strategically invest capital to grow our cash from operations. We believe our commitment to our value proposition, as evidenced by the results discussed below, positions us for success in an environment of price uncertainty and ongoing volatility.

In the first nine months of the year, we took significant actions resulting in substantial progress on our priorities. We increased our quarterly dividend by 7.5 percent to $0.285 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 and Moody's; repurchased 31.4 million shares of our common stock totaling $2.1 billion; and added to our low cost of supply resource base by increasing our legacy asset position in Alaska through one closed and one announced transaction.

In July 2018, we announced an expansion of the planned 2018 share repurchase program from $2 billion to $3 billion. We expect to fully fund this year's $3 billion program, as well as our dividend and capital expenditures, with cash provided by operating activities. Cash provided by operating activities for the first nine months of 2018 was $9.2 billion, which exceeded capital expenditures and investments of $5.1 billion, including $0.5 billion of acquisition capital; dividends of $1.0 billion; and share repurchases of $2.1 billion.

The 2018 expansion to $3 billion, combined with the $3 billion of shares repurchased during 2016 and 2017, will fully utilize our Board of Directors' previous share repurchase authorization of $6 billion. As a result, in July 2018 our Board authorized an additional $9 billion for share repurchases, bringing the total program authorization to $15 billion.

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 the second quarter of 2018, we obtained regulatory approvals to complete the 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 Pipeline, for $386 million, after customary adjustments. Full-year 2017 production associated with this interest was 11 thousand barrels of oil equivalent per day (MBOED). 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 third quarter of 2018, we entered into agreements with BP to acquire their nonoperated interest in the Greater Kuparuk Area and Kuparuk Transportation Company (Kuparuk Assets) in Alaska, and to sell a ConocoPhillips subsidiary to BP, which will hold 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. Both transactions are subject to regulatory approval and are expected to close simultaneously in late 2018. Full-year 2017 production and year-end 2017 proved reserves associated with the 16.5 percent interest in the Clair Field were approximately 3 MBOED and approximately 40 million barrels of oil equivalent (MMBOE), respectively. Full-year 2017 production and year-end 2017 proved reserves associated with the 39.2 percent interest in the Greater Kuparuk Area were approximately 38 MBOED and 190 MMBOE, respectively. Excluding customary adjustments, the transactions are expected to be cash neutral. Depending on the timing of regulatory approvals, we anticipate recognizing a noncash gain of between $0.5 billion and $1.0 billion on completion of the sale of the ConocoPhillips subsidiary holding 16.5 percent of the Clair Field, after customary adjustments and foreign exchange impacts.

In October 2018, we announced an agreement to sell our 30 percent interest in the Greater Sunrise Fields for $350 million, prior to customary adjustments, to the government of Timor-Leste, with an expected closing date of early 2019. The transaction is conditional on the funding approval from the Timor-Leste Council of Ministers and National Parliament. The interest to be sold is undeveloped property in the Timor Sea located between Australia and Timor-Leste. No production or reserve impacts are associated with the sale. Proceeds from this transaction will be used for general corporate purposes.

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

In the third quarter of 2018, we entered into a settlement agreement with Petroleos de Venezuela, S.A. (PDVSA) to recover approximately $2 billion, which reflects the full amount awarded to ConocoPhillips by an arbitral tribunal constituted under the rules of the International Chamber of Commerce (ICC). PDVSA has agreed to recognize the ICC judgment and to make payments over the next four and a half years. During the quarter, we recognized in other income $345 million, consisting of $242 million in commodity inventory and $103 million in cash, related to this settlement. For more information, see Note 4—Inventories and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

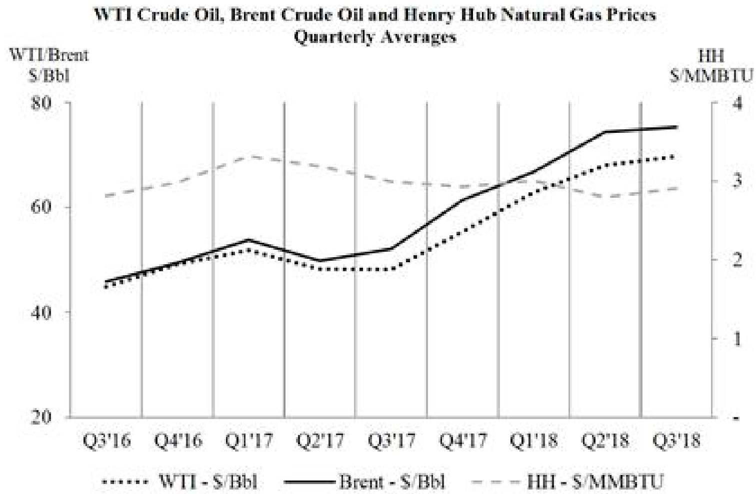
Operationally, we continue to focus on safely executing our capital program and remaining attentive to our costs. Production excluding Libya was 1,224 MBOED in the third quarter of 2018, an increase of 22 MBOED compared with the same period of 2017. Our underlying production, which excludes Libya and the third-quarter impact of dispositions of approximately 50 MBOED in 2017, increased 6 percent compared with the same period of 2017. Underlying production on a per debt-adjusted share basis grew by 28 percent compared with the third quarter of 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.

Business Environment

Global oil market fundamentals continued to strengthen in the third quarter of 2018. Crude oil prices improved in the period because of supply disruptions and strong global oil demand.

The energy industry has periodically experienced 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. Among other dynamics that could influence world energy markets and commodity prices are global economic health, supply disruptions or fears thereof caused by civil unrest, military conflicts or otherwise, actions taken by the Organization of Petroleum Exporting Countries (OPEC), environmental laws, tax regulations, governmental policies and weather-related disruptions. North America's energy landscape has been transformed from resource scarcity to an abundance of supply, primarily due to advances in technology responsible for the rapid growth of tight oil production, successful exploration and rising production from the Canadian oil sands. Our strategy is to create value through price cycles by delivering on the financial and operational priorities that underpin our value proposition.

Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas, the prices of which are subject to factors external to the company and over which we have no control. The following graph depicts the trend in average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and Henry Hub natural gas:



Brent crude oil prices averaged $75.27 per barrel in the third quarter of 2018, an increase of 44 percent compared with $52.09 per barrel in the third quarter of 2017, and an increase of 1 percent compared with $74.35 per barrel in the second quarter of 2018. Crude oil prices for WTI averaged $69.71 per barrel in the third quarter of 2018, an increase of 45 percent compared with $48.16 per barrel in the third quarter of 2017, and an increase of 3 percent compared with $67.99 per barrel in the second quarter of 2018. Prices improved relative to the same period a year ago due to strong oil demand and global supply disruptions.

Henry Hub natural gas prices averaged $2.91 per million British thermal units (MMBTU) in the third quarter of 2018, a decrease of 3 percent compared with $2.99 per MMBTU in the third quarter of 2017, and an increase of 4 percent compared with $2.80 per MMBTU in the second quarter of 2018. Prices decreased relative to the same period of 2017 due to higher gas production in the contiguous United States.

Our realized bitumen price increased from $24.19 per barrel in the third quarter of 2017 to $34.15 per barrel in the same period of 2018, primarily due to improvements in the WTI benchmark price and reduced blend ratios at Surmont from use of condensate diluent, partially offset by the widening of the Western Canada Select (WCS) differential. Compared with $32.38 per barrel in the second quarter of 2018, our third quarter 2018 realized bitumen price increased due to improvements in the WTI benchmark price, as well as reduced blend ratios at Surmont. The improvement in our realized bitumen price was partly offset by turnarounds in U.S. midcontinent refineries, particularly during the latter part of the third quarter, resulting in reduced demand for Canadian heavy crude and contributing to a weaker WCS-WTI Edmonton differential versus the prior quarter.

Our total average realized price was $57.71 per barrel of oil equivalent (BOE) in the third quarter of 2018, an increase of 46 percent compared with $39.49 per BOE in the third quarter of 2017 and a 6 percent increase compared with the second quarter of 2018, primarily reflecting higher average realizations for crude oil and LNG sales, and a more liquids weighted portfolio.

Key Operating and Financial Summary

Significant items during the third quarter of 2018 included the following:

- Cash provided by operating activities was $3.4 billion and exceeded capital expenditures and investments, dividends and share repurchases.
- Third-quarter production excluding Libya of 1,224 MBOED; year-over-year underlying production excluding the impact of closed dispositions grew 6 percent overall and 28 percent on a production per debt-adjusted share basis.
- Year-over-year production from the Lower 48 Big 3 unconventional plays—Eagle Ford, Bakken and Delaware—grew by 48 percent.
- During the quarter, achieved first production from Bohai Phase 3 and from the final phase of drilling at Bayu-Undan.
- Ended the quarter with cash, cash equivalents and restricted cash totaling $3.9 billion and short-term investments of $0.9 billion, equating to $4.8 billion.
- Repurchased $0.9 billion of common shares outstanding, bringing year-to-date repurchases to $2.1 billion.
- Reached a settlement agreement with PDVSA to recover an arbitration award of approximately $2 billion; recognized cash and commodities totaling $345 million in the quarter, with the remainder of the approximately $500 million in initial payments due in the fourth quarter.
- Announced Barnett and Greater Sunrise dispositions for $580 million before customary adjustments.
- Received credit rating upgrades from Fitch and Moody’s.
- In October, announced a quarterly dividend increase of 7 percent to 30.5 cents per share.

Outlook

Production and Capital Guidance
Fourth-quarter 2018 production is expected to be 1,275 to 1,315 MBOED, reflecting the completion of seasonal turnarounds and growth from several conventional project startups and ongoing development in the unconventionals. This guidance includes impacts expected from the previously announced Barnett disposition and excludes Libya.

Full-year 2018 capital expenditures and investments are expected to be $6.6 billion in 2018. The company’s 2018 operated capital scope remains unchanged, excluding acquisition-related activity. However, the company is adjusting its capital expenditures guidance to $6.1 billion from the original $5.5 billion budget. This guidance excludes the previously announced $0.4 billion bolt-on acquisition in the Alaska Western North Slope and $0.1 billion to acquire additional acreage in the Montney in Canada.

RESULTS OF OPERATIONS

Unless otherwise indicated, discussion of results for the three- and nine-month periods ended September 30, 2018, is based on a comparison with the corresponding periods of 2017.

Consolidated Results

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

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Alaska	**$ 427**	103	**1,369**	291
Lower 48	**513**	(97)	**1,231**	(2,995)
Canada	**34**	280	**2**	2,607
Europe and North Africa	**241**	85	**776**	379
Asia Pacific and Middle East	**577**	396	**1,504**	(1,540)
Other International	**316**	(20)	**267**	(77)
Corporate and Other	**(247)**	(327)	**(760)**	(1,099)
Net income (loss) attributable to ConocoPhillips	**$ 1,861**	420	**4,389**	(2,434)

Net income attributable to ConocoPhillips in the third quarter of 2018 increased $1,441 million. Earnings were positively impacted by:

- Higher realized commodity prices.
- Higher crude oil sales volumes.
- Recognition of $325 million after-tax from a settlement agreement with PDVSA.
- Lower depreciation, depletion and amortization (DD&A) expense, mainly due to lower unit-of-production rates from reserve additions and disposition impacts.

Third quarter 2018 net income increases were partly offset by:

- The absence of a $190 million after-tax gain in the third quarter of 2017 for funds received in relation to environmental claims related to certain Canadian assets sold in 2017.
- The absence of a $114 million tax benefit in the third quarter of 2017 related to our decision to exit Nova Scotia deepwater exploration.
- Higher production and operating expenses, primarily due to higher maintenance and wellwork.

Net income attributable to ConocoPhillips in the nine-month period ended September 30, 2018, increased $6,823 million. Earnings were positively impacted by:

- The absence of a $2.5 billion after-tax impairment recognized in the second quarter of 2017, related to the sale of our interests in the San Juan Basin and the marketing of our Barnett asset.
- 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.
- Higher realized commodity prices.
- Lower DD&A expense, mainly due to lower unit-of-production rates from reserve additions and disposition impacts.
- Recognition of $325 million after-tax from a settlement agreement with PDVSA.

- 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, and higher sales volumes from QG3.
- A $109 million after-tax benefit, including interest, in the first quarter of 2018, resulting from an accrual reduction due to a transportation cost ruling in Alaska by the Federal Energy Regulatory Commission (FERC).

Earnings in the nine-month period ended September 30, 2018, were negatively impacted 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 in the first quarter of 2017 related to the disposition of certain Canadian assets.
- Lower sales volumes, primarily due to dispositions in our Lower 48 and Canada segments in 2017 and normal field decline.

See the "Segment Results" section for additional information.

Income Statement Analysis

Sales and other operating revenues for the three- and nine-month periods of 2018 increased 41 percent and 27 percent, respectively, mainly due to higher realized prices across all commodities. In the nine-month period of 2018, these increases were partly offset by lower sales volumes, primarily in our Canada and Lower 48 segments, due to 2017 disposition activity.

Equity in earnings of affiliates for the three- and nine-month periods of 2018 increased 50 percent and 34 percent, respectively, primarily due to higher earnings from QG3 and APLNG as a result of higher LNG prices for both affiliates and higher sales volumes from QG3. The absence of equity in earnings from FCCL following our disposition to Cenovus Energy in the second quarter of 2017 partly offset the increase in nine-month 2018 earnings.

Gain on dispositions for the third quarter of 2018 decreased $133 million, primarily due to the absence of a $281 million before-tax gain related to the sale of certain Canadian assets recognized in the third quarter of 2017, partly offset by a gain on an unproved property exchange in the Lower 48 in the third quarter of 2018. Gain on dispositions in the nine-month period of 2018 decreased $2.0 billion, primarily due to the absence of a $2.1 billion before-tax gain on the 2017 Canadian asset sale. For more information on dispositions, see Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions, in the Notes to Consolidated Financial Statements.

Other income for the third quarter of 2018 increased $244 million, primarily due to recognizing $345 million related to a settlement agreement with PDVSA, partly offset by a $73 million before-tax net unrealized loss on our Cenovus Energy common shares. In the nine-month period of 2018, other income increased $530 million primarily due to recognizing $345 million related to the settlement agreement with PDVSA referenced above, as well as a $187 million before-tax unrealized gain on our Cenovus Energy common shares.

For discussion of our PDVSA settlement, see Note 4—Inventories and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements. For discussion of our Cenovus Energy shares, see Note 7—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements.

Purchased commodities for the three- and nine-month periods of 2018 increased 21 and 14 percent, respectively, primarily due to higher crude oil prices and higher crude volumes purchased, partly offset by lower natural gas prices during the nine-month period.

Production and operating expenses for the three- and nine-month periods of 2018 increased $145 million and $13 million, respectively, primarily due to costs associated with higher underlying production volumes as well as higher maintenance and wellwork, largely offset by lower costs from disposition impacts in our Canada and Lower 48 segments during the nine-month period of 2018.

Exploration expenses decreased $453 million in the nine-month period of 2018, primarily due to the absence of first quarter 2017 dry hole and leasehold impairment costs of $342 million associated with the Shenandoah prospect in deepwater Gulf of Mexico as well as 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.

DD&A for the three- and nine-month periods of 2018 decreased 7 percent and 17 percent, respectively, mainly due to lower unit-of-production rates from reserve additions and disposition impacts in our Canada and Lower 48 segments, partly offset by increased underlying production volumes.

Impairments decreased $6.4 billion in the nine-month period of 2018, mainly due to the absence of second quarter 2017 impairments of $3.3 billion before-tax for our interests in the San Juan Basin and $0.6 billion before-tax for our interests in 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 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes for the three- and nine-month periods of 2018 increased $137 million and $164 million, respectively, primarily due to higher production taxes in Alaska and the Lower 48 corresponding with higher realized commodity prices.

Interest and debt expense decreased $65 million and $325 million in the three- and nine-month periods of 2018, respectively, because of lower debt balances.

See Note 22—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

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Summary Operating Statistics

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Average Net Production				
Crude oil (MBD)(1)	**635**	582	**632**	591
Natural gas liquids (MBD)	**106**	95	**102**	119
Bitumen (MBD)	**65**	63	**65**	140
Natural gas (MMCFD)(2)	**2,732**	2,918	**2,771**	3,405
Total Production (MBOED)(3)	**1,261**	1,226	**1,261**	1,418

	Dollars Per Unit			
Average Sales Prices				
Crude oil (per barrel)	**73.05**	49.39	**69.74**	49.51
Natural gas liquids (per barrel)	**35.14**	23.82	**31.31**	23.25
Bitumen (per barrel)	**34.15**	24.19	**26.46**	22.25
Natural gas (per thousand cubic feet)	**5.81**	4.11	**5.37**	3.91

	Millions of Dollars			
Exploration Expenses				
General administrative, geological and geophysical, lease rental, and other	**$ 75**	66(4)	**203**	285(4)
Leasehold impairment	**16**	10	**36**	81
Dry holes	**12**	(3)	**28**	354
	$ 103	73(4)	**267**	720(4)

(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 amounts have been reclassified to conform to the current period presentation as a result of 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 September 30, 2018, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Total production increased 35 MBOED or 3 percent in the third quarter of 2018, primarily due to:

- New wells online in the Lower 48, Norway and China.
- The absence of Hurricane Harvey impacts on our Lower 48 segment in the third quarter of 2017.
- The continued ramp-up in Libya.
- An increased interest in the Western North Slope of Alaska following our second quarter 2018 acquisition.

The increase in third quarter 2018 production was partly offset by:

- Normal field decline.
- Disposition impacts in the Lower 48 from the sale of San Juan and other noncore assets in 2017.
- Higher unplanned downtime, mainly in the Lower 48 and Malaysia.

Total production decreased 157 MBOED or 11 percent in the nine-month period of 2018, primarily due to:

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

The decrease in production during the nine-month period of 2018 was partly offset by:

- New wells online from tight oil plays in the Lower 48, Malikai in Malaysia, and Surmont and Montney in Canada.
- Improved drilling and well performance in Alaska, Lower 48, Norway and China.
- The continued ramp-up in Libya.

Production excluding Libya was 1,224 MBOED in the third quarter of 2018, an increase of 22 MBOED compared with the same period of 2017. Our underlying production, which excludes Libya and the third-quarter impact of dispositions of approximately 50 MBOED in 2017, increased 6 percent compared with the same period of 2017.

Segment Results

Alaska

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Income Attributable to ConocoPhillips (millions of dollars)	$ **427**	103	1,369	291
Average Net Production				
Crude oil (MBD)	**152**	154	**165**	166
Natural gas liquids (MBD)	**12**	11	**14**	14
Natural gas (MMCFD)	**5**	5	**6**	7
Total Production (MBOED)	**165**	166	**180**	181
Average Sales Prices				
Crude oil (dollars per barrel)	$ **76.47**	50.53	**72.44**	50.81
Natural gas (dollars per thousand cubic feet)	**2.52**	4.55	**2.51**	2.77

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids and natural gas. As of September 30, 2018, Alaska contributed 22 percent of our worldwide liquids production and less than 1 percent of our worldwide natural gas production.

Earnings from Alaska for the three- and nine-month periods ended September 30, 2018, increased $324 million and $1,078 million, respectively, compared with the corresponding periods in 2017. The increase in earnings for both periods was primarily due to higher realized crude oil prices. Additionally, earnings in the nine-month period of 2018 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; 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 FERC, recorded in the first quarter of 2018.

Average production was down 1 MBOED in the three- and nine-month periods of 2018 compared with the corresponding periods in 2017, primarily due to higher planned downtime and normal field decline, partly offset by production increases from improved drilling and well performance. In the third quarter of 2018, production included 8 MBOED due to the acquisition in the Western North Slope discussed below.

Acquisitions
During the second quarter of 2018, we obtained regulatory approvals and completed the 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 Pipeline, for $386 million, after customary adjustments. In 2017, the net production associated with this interest was 11 MBOED. In addition, we now have 100 percent interest in approximately 1.2 million acres of exploration and development lands, including the Willow discovery.

In July 2018, we entered into agreements with BP to acquire their nonoperated interest in the Greater Kuparuk Area and Kuparuk Transportation Company in Alaska, and to sell a ConocoPhillips subsidiary to BP, which will hold 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. Both transactions are subject to regulatory approvals and are expected to close simultaneously in 2018. Full-year 2017 production and year-end 2017 proved reserves associated with the 39.2 percent interest in the Greater Kuparuk Area were approximately 38 MBOED and 190 MMBOE, respectively.

See Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions in the Notes to Consolidated Financial Statements, for additional information.

Lower 48

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	2018	2017
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$ **513**	(97)	1,231	(2,995)
Average Net Production				
Crude oil (MBD)	**240**	175	**218**	176
Natural gas liquids (MBD)	**73**	64	**68**	73
Natural gas (MMCFD)	**608**	765	**589**	1,007
Total Production (MBOED)	**414**	366	384	417
Average Sales Prices				
Crude oil (dollars per barrel)	$ **67.73**	45.29	**65.38**	44.84
Natural gas liquids (dollars per barrel)	**32.17**	20.72	**28.06**	20.55
Natural gas (dollars per thousand cubic feet)	**2.80**	2.63	**2.63**	2.74

The Lower 48 segment consists of operations located in the U.S. Lower 48 states, as well as producing properties in the Gulf of Mexico. As of September 30, 2018, the Lower 48 contributed 37 percent of our worldwide liquids production and 21 percent of our worldwide natural gas production.

Earnings from the Lower 48 for the three- and nine-month periods of 2018 increased $610 million and $4,226 million, respectively, compared with corresponding periods in 2017. Both periods benefitted from higher realized crude oil and NGL prices and higher crude oil sales volumes. Earnings in the third quarter of 2018 also increased due to a $44 million after-tax gain related to an undeveloped property exchange.

Earnings in the nine-month period of 2018 increased due to the absence of second quarter 2017 impairments totaling $2.5 billion after-tax for our interests in the San Juan Basin and the Barnett; lower DD&A expense, primarily due to reserve additions and asset disposition impacts, partly offset by higher underlying volumes; and lower exploration expenses. Exploration expenses were lower, mainly due to the absence of first quarter 2017 dry hole and impairment charges of $189 million after-tax and $33 million after-tax, respectively, for multiple Shenandoah wells and associated leases.

Total average production for the three- and nine-month periods of 2018, adjusted for dispositions and Hurricane Harvey, increased approximately 27 percent and 22 percent, respectively. These underlying production increases were primarily due to new production from Eagle Ford, Bakken and the Permian Basin, partly offset by normal field decline. Disposition impacts from the sale of San Juan and other noncore asset sales were approximately 50 MBOED and 105 MBOED in the three- and nine-month periods of 2017, respectively. Production in the third quarter of 2017 was impacted by 15 MBOED from Hurricane Harvey.

Asset Dispositions Update
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 third quarter of 2018, we signed a definitive agreement to sell our interest in the Barnett for approximately $230 million, plus customary adjustments. Full-year 2017 production associated with the Barnett averaged 10 MBOED, of which approximately 55 percent was natural gas and 45 percent was natural gas liquids. After-tax impairment charges of $33 million and $68 million were recognized in the three- and nine-month periods of 2018, respectively, to reduce the carrying value to fair value less costs to sell. The transaction is expected to close by year-end 2018.

See Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions in the Notes to Consolidated Financial Statements, for additional information.

Acquisition

During the fourth quarter of 2017, we acquired approximately 200,000 net acres of early life-cycle unconventional acreage in the Austin Chalk play in central Louisiana for approximately $200 million. We began an exploration drilling program in the fourth quarter of 2018.

Canada

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Income Attributable to ConocoPhillips (millions of dollars)	**$ 34**	280	**2**	2,607
Average Net Production				
Crude oil (MBD)	**1**	1	**1**	3
Natural gas liquids (MBD)	**2**	1	**1**	12
Bitumen (MBD)				
Consolidated operations	**65**	63	**65**	56
Equity affiliates	**—**	—	**—**	84
Total bitumen	**65**	63	**65**	140
Natural gas (MMCFD)	**12**	10	**13**	246
Total Production (MBOED)	**70**	67	**69**	196
Average Sales Prices				
Crude oil (dollars per barrel)	$ —	—	**—**	43.46
Natural gas liquids (dollars per barrel)	**—**	—	**—**	21.44
Bitumen (dollars per barrel)*				
Consolidated operations	**34.15**	24.19	**26.46**	19.93
Equity affiliates	**—**	—	**—**	23.83
Total bitumen	**34.15**	24.19	**26.46**	22.25
Natural gas (dollars per thousand cubic feet)	**—**	—	**—**	1.95

**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. As of September 30, 2018, Canada contributed 8 percent of our worldwide liquids production and less than 1 percent of our worldwide natural gas production.

Earnings from Canada decreased $246 million in the third quarter of 2018 compared with the corresponding period in 2017, primarily due to the absence of a $190 million after-tax gain for funds received in relation to environmental claims related to disposition activity and the absence of a $114 million tax benefit related to our decision to exit Nova Scotia, both recognized in the third quarter of 2017. Partly offsetting these impacts were higher realized bitumen prices.

Earnings from Canada decreased $2.6 billion in the nine-month period of 2018 compared with the corresponding period in 2017, primarily due to the absence of earnings associated with certain Canadian assets, including our interest in the FCCL Partnership, sold to Cenovus Energy in the second quarter of 2017. The nine-month period of 2017 included $1.6 billion in after-tax gains, $1.0 billion in deferred tax benefits, and equity earnings in the FCCL Partnership.

For additional information on the 2017 Canada disposition, see Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions and Note 7—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements.

Total average production increased 4 percent in the third quarter of 2018, primarily due to lower planned downtime and improved drilling and well performance. Total average production decreased 65 percent in the nine-month period of 2018, primarily due to our 2017 Canada disposition, partly offset by new wells online at Surmont and Montney.

Acquisition
In February 2018, we acquired approximately 34,500 net acres of undeveloped land in the Montney in Canada 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.

Europe and North Africa

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Income Attributable to ConocoPhillips (millions of dollars)	$ **241**	85	**776**	379
Average Net Production				
Crude oil (MBD)	**145**	141	**147**	139
Natural gas liquids (MBD)	**8**	7	**8**	8
Natural gas (MMCFD)	**452**	408	**502**	475
Total Production (MBOED)	**229**	216	**240**	227
Average Sales Prices				
Crude oil (dollars per barrel)	$ **76.54**	51.05	**71.38**	51.90
Natural gas liquids (dollars per barrel)	**38.80**	31.16	**37.75**	29.69
Natural gas (dollars per thousand cubic feet)	**7.62**	5.09	**7.40**	5.34

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. As of September 30, 2018, our Europe and North Africa operations contributed 19 percent of our worldwide liquids production and 18 percent of our worldwide natural gas production.

Earnings for Europe and North Africa increased by $156 million and $397 million in the three- and nine-month periods of 2018, respectively, compared with the corresponding periods in 2017, primarily due to higher realized crude oil and natural gas prices and lower DD&A expense due to reserve additions. Additionally, earnings in the nine-month period of 2018 increased by $31 million after-tax because of a reduction to impairment due to decreased asset retirement obligation estimates for a certain field in the United Kingdom which was impaired in prior years, offset by the absence of a $41 million tax benefit in Norway, recorded in the second quarter of 2017.

Average production increased 6 percent in both the three- and nine-month periods of 2018 compared with the corresponding periods in 2017, primarily due to higher production in Libya, improved drilling and well performance 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. Full-year 2017 average net production in the Southern North Sea was 46 million cubic feet a day or 8 MBOED.

Libya production was shut-in from mid-June 2018 through the end of the second quarter because of the Es Sider crude oil export terminal closure following a period of civil unrest. Exports resumed in July 2018.

Disposition

In July 2018, we entered into agreements with BP to acquire their nonoperated interest in the Greater Kuparuk Area and Kuparuk Transportation Company in Alaska, and to sell a ConocoPhillips subsidiary to BP, which will hold 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the United Kingdom. Both transactions are subject to regulatory approvals and are expected to close simultaneously in 2018. Excluding customary adjustments, the transactions are expected to be cash neutral. Full-year 2017 production and year-end 2017 proved reserves associated with the 16.5 percent interest in the Clair Field were approximately 3 MBOED and 40 MMBOE, respectively. Depending on the timing of regulatory approvals, we anticipate recognizing a noncash gain of between $0.5 billion to $1.0 billion on completion of the sale of the

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ConocoPhillips subsidiary holding 16.5 percent of the Clair Field, after customary adjustments and foreign exchange impacts. See Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions, for additional information.

Asia Pacific and Middle East

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$ **577**	396	**1,504**	(1,540)
Average Net Production				
Crude oil (MBD)				
Consolidated operations	**84**	97	**87**	93
Equity affiliates	**13**	14	**14**	14
Total crude oil	**97**	111	**101**	107
Natural gas liquids (MBD)				
Consolidated operations	**3**	4	**3**	5
Equity affiliates	**8**	8	**8**	7
Total natural gas liquids	**11**	12	**11**	12
Natural gas (MMCFD)				
Consolidated operations	**630**	690	**617**	673
Equity affiliates	**1,025**	1,040	**1,044**	997
Total natural gas	**1,655**	1,730	**1,661**	1,670
Total Production (MBOED)	**383**	411	**388**	397
Average Sales Prices				
Crude oil (dollars per barrel)				
Consolidated operations	$ **74.78**	52.06	**71.98**	51.73
Equity affiliates	**76.62**	52.29	**73.00**	52.87
Total crude oil	**75.02**	52.10	**72.13**	51.88
Natural gas liquids (dollars per barrel)				
Consolidated operations	**52.30**	35.74	**48.15**	38.28
Equity affiliates	**49.71**	35.94	**45.74**	37.59
Total natural gas liquids	**50.71**	35.86	**46.48**	37.84
Natural gas (dollars per thousand cubic feet)				
Consolidated operations	**6.53**	4.63	**5.88**	4.87
Equity affiliates	**6.35**	4.51	**5.70**	4.28
Total natural gas	**6.42**	4.56	**5.76**	4.52

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. As of September 30, 2018, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 61 percent of our worldwide natural gas production.

Earnings increased $181 million and $3,044 million in the three- and nine-month periods of 2018, respectively, compared with the corresponding periods in 2017. Both periods benefitted from higher realized prices and improved equity earnings from APLNG and QG3, primarily due to higher realized LNG prices for both periods and higher sales volumes from QG3 during the nine-month period of 2018. Additionally, the nine-month period of 2018 was improved due to the absence of a $2,384 million before- and after-tax charge for the impairment of our APLNG investment, recorded in the second quarter of 2017. See the “APLNG” section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on the impairment of our APLNG investment.

Average production decreased 7 percent and 2 percent in the three- and nine-month periods of 2018, respectively, compared with the corresponding periods in 2017. In both periods, production decreased due to normal field decline; 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 production curtailment in Qatar. These impacts were partly offset by an infill drilling program in China and new wells online at Malakai in Malaysia.

Asset Disposition Update
In October 2018, we announced an agreement to sell our 30 percent interest in the Greater Sunrise Fields for $350 million, prior to customary adjustments, to the government of Timor-Leste, with an expected closing date in early 2019. The transaction is conditional on funding approval from the Timor-Leste Council of Ministers and National Parliament, as well as regulatory approvals and partner pre-emption rights. The interest to be sold is undeveloped property in the Timor Sea located between Australia and Timor-Leste. No production or reserve impacts are associated with the sale.

Other International

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	**$ 316**	(20)	**267**	(77)

The Other International segment primarily consists of exploration activities in Colombia and Chile.

Earnings from our Other International segment increased $336 million and $344 million in the three- and nine-month periods of 2018, respectively, compared with the corresponding periods in 2017. The increase in earnings is primarily due to recognizing $325 million after-tax in other income under a settlement agreement with PDVSA associated with prior operations. See Note 4—Inventories and Note 13—Contingencies and Commitments in the Notes to Consolidated Financial Statements, for additional information.

Additionally, in the nine-month period of 2018, earnings increased due to the absence of a $28 million after-tax charge for the cancellation of our Athena drilling rig contract and rig stacking costs in Angola, in the first quarter of 2017. Partially offsetting this increase in earnings, was a $34 million tax settlement charge, recognized in the first quarter of 2018, associated with prior operations in Nigeria.

Corporate and Other

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Net Loss Attributable to ConocoPhillips				
Net interest	$ **(174)**	(176)	**(508)**	(603)
Corporate general and administrative expenses	**(36)**	(42)*	**(139)**	(132)*
Technology	**64**	20	**117**	29
Other	**(101)**	(129)*	**(230)**	(393)*
	$ **(247)**	(327)	**(760)**	(1,099)

**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.*

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest was reduced by $2 million and $95 million in the three- and nine-month periods ended September 30, 2018, respectively. Both periods benefitted from less interest from lower debt balances and higher capitalized interest on projects, partly offset by impacts from the fair market value method of apportioning interest expense in the United States, and reduced tax benefit on interest expense following the Tax Cuts and Jobs Act (Tax Legislation), which lowered the U.S. corporate income tax rate from 35 percent to 21 percent effective January 1, 2018. The nine-month period of 2018 benefitted from lower interest due to an accrual reduction given a transportation cost ruling by the FERC in the first quarter of 2018, and higher interest income.

Corporate general and administrative expenses include compensation programs and staff costs. These expenses decreased by $6 million and increased by $7 million in the three- and nine-month periods of 2018, respectively.

Technology includes our investment in new technologies or businesses, as well as licensing revenues. Activities are focused on tight oil reservoirs, heavy oil and oil sands, as well as LNG. Earnings from Technology increased $44 million and $88 million in the three- and nine-month periods of 2018, respectively, primarily due to higher licensing revenues. See Note 20—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 $28 million in the third quarter of 2018, primarily due to lower taxes and the absence of premiums associated with the early retirement of debt, both recognized in the third quarter of 2017, partly offset by an unrealized loss on our Cenovus Energy common shares in the third quarter of 2018. Losses in “Other” decreased by $163 million in the nine-month period of 2018, primarily due to an unrealized gain on our Cenovus Energy common shares and lower premiums associated with the early retirement of debt, partly offset by higher pension settlement expense.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars	
	September 30 2018	December 31 2017
Short-term debt	**$ 95**	2,575
Total debt	**14,997**	19,703
Total equity	**32,079**	30,801
Percent of total debt to capital*	**32%**	39
Percent of floating-rate debt to total debt	**5%**	5

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, our commercial paper and credit facility programs, and our shelf registration statement. During the first nine months of 2018, the primary uses of our available cash were $5,133 million to support our ongoing capital expenditures and investments program, $4,970 million to reduce debt, $2,073 million to repurchase common stock, and $1,009 million to pay dividends. During the first nine months of 2018, our cash, cash equivalents and restricted cash decreased by $2,596 million to $3,940 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, dividend payments and required debt payments.

Significant Sources of Capital

Operating Activities
Cash provided by operating activities was $9,151 million for the first nine months of 2018, compared with $4,596 million for the corresponding period of 2017. The increase was primarily due to higher realized prices across all commodities.

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

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Production levels are impacted by such factors as 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, we must continue to add to our proved reserve base. As we undertake cash prioritization efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves.

Investing Activities
Proceeds from asset sales for the first nine months of 2018 were $394 million compared with $13,740 million for the corresponding period of 2017. In the first nine months of 2018, we completed the sale of several properties in the Lower 48 segment for net proceeds of $317 million and received $50 million of contingent payments from Cenovus Energy. In the first nine months of 2017, we completed several dispositions including the sale of certain Canadian assets to Cenovus Energy for cash proceeds of $11 billion, the sale of our interests in the San Juan Basin for proceeds of $2.5 billion in cash after customary adjustments, and the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments. All cash deposits and proceeds from asset dispositions are included in the "Cash Flows From Investing Activities" section of our consolidated statement of cash flows. For more information on asset dispositions, see Note 5—Assets Held for Sale, Dispositions, Acquisitions and Other Planned Transactions.

Commercial Paper and Credit Facilities
In May 2018, we refinanced our revolving credit facility from a total aggregate principal 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 our 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 September 30, 2018 or December 31, 2017. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at September 30, 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 September 30, 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 their rating on our long-term debt from "Baa1" to "A3" and adjusted their outlook for our debt from "positive" to "stable." As of September 30, 2018, Standard & Poor's rating for our long-term debt was "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 September 30, 2018 and December 31, 2017, we had direct bank letters of credit of $275 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.

Capital Requirements

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

Our debt balance at September 30, 2018, was $15 billion, which we announced as our stated debt target in November 2017. We achieved that goal in the second quarter of 2018, significantly earlier than the original target date of year-end 2019. The $15 billion debt balance is a decrease of $4.7 billion from the balance at December 31, 2017.

In the first quarter of 2018, we redeemed or repurchased a total of $2,650 million of debt as described below:

- 4.20% Notes due 2021 with remaining principal of $1.0 billion.
- 2.875% Notes due 2021 with principal of $750 million.
- 2.2% Notes due 2020 with principal of $500 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).

In the second quarter of 2018, we repurchased a total of $1,800 million of debt as described below:

- 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).
- 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).

During the first six months of 2018, we incurred net premiums above book value to redeem or repurchase these debt instruments of $208 million.

In the second quarter of 2018, we also repaid the $250 million floating rate note due in 2018 at its natural maturity. For information on debt, see Note 10—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, payable December 3, 2018, to stockholders of record at the close of business on October 15, 2018.

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 plan to repurchase $3 billion in 2018. We expect the 2018 program to be funded with cash from operations. On July 12, 2018, we announced an authorization of an additional $9 billion in share repurchases bringing the total program authorization to $15 billion.

Since our share repurchase program began in November 2016, we have repurchased 97 million shares at a cost of $5.2 billion through September 30, 2018.

Capital Expenditures

	Millions of Dollars Nine Months Ended September 30	
	2018	2017
Alaska	**$ 1,034**	636
Lower 48	**2,475**	1,234
Canada	**318**	180
Europe and North Africa	**678**	657
Asia Pacific and Middle East	**493**	316
Other International	**6**	17
Corporate and Other	**129**	34
Capital expenditures and investments	**$ 5,133**	3,074

During the first nine months of 2018, capital expenditures and investments supported key exploration and development programs, primarily:

- Development, appraisal, and exploration activities in the Lower 48, including Eagle Ford, Bakken, and 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 Malaysia, Indonesia, China and Australia and exploration and appraisal activities in Malaysia.

Total capital expenditures and investments for all activity is expected to be $6.6 billion. The company’s 2018 operated capital scope remains unchanged, excluding acquisition-related activity. However, the company is adjusting its capital expenditures guidance to $6.1 billion from the original $5.5 billion budget. This guidance excludes the previously announced $0.4 billion bolt-on acquisition in the Alaska Western North Slope and $0.1 billion to acquire additional acreage in the Montney in Canada.

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. 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. For information on other contingencies, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Legal 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.

Environmental
We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. For a discussion of the most significant of these environmental laws and regulations, including those with associated remediation obligations, see the “Environmental” section in Management’s Discussion and Analysis of Financial Condition and Results of Operations on pages 61–63 of our 2017 Annual Report on Form 10-K.

We occasionally receive requests for information or notices of potential liability from the Environmental Protection Agency (EPA) and state environmental agencies alleging that we are a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act (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 waste attributable to our past operations. As of September 30, 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.

At September 30, 2018, our balance sheet included a total environmental accrual of $170 million, compared with $180 million at December 31, 2017, for remediation activities in the United States and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

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

Climate Change

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

For other examples of legislation or precursors for possible regulation and factors on which the ultimate impact on our financial performance will depend, see the "Climate Change" section in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 63–64 of our 2017 Annual Report on Form 10-K.

In 2017 and 2018, cities, counties, and/or state governments in California, New York, Washington, Rhode Island and Maryland 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.

NEW ACCOUNTING STANDARDS

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, “Leases” (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB Accounting Standards Codification (ASC) Topic 840, “Leases” (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, the FASB issued ASU No. 2018-11, “Targeted Improvements” (ASU No. 2018-11), in July 2018 to set forth certain additional practical expedients for lessors and to provide 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 continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. We are currently implementing a third-party lease accounting software solution to facilitate the ongoing accounting and financial reporting requirements of the ASU. We also continue to monitor proposals issued by the FASB to clarify the ASU and certain industry implementation issues.

While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact to our consolidated financial statements. Such impact is expected to relate primarily to our balance sheet, resulting from the initial recognition of lease liabilities and corresponding right-of-use assets for our population of operating leases, as well as enhanced disclosure of our leasing arrangements. We also expect the adoption of ASU No. 2016-02 to result in certain changes being made to our existing accounting policies and systems, business processes, and internal controls. For additional information, see Note 23—New Accounting Standards, in the Notes to Consolidated Financial Statements.

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

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

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

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

- Changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil, bitumen, natural gas, LNG, natural gas liquids and any materials or products (such as aluminum and steel) used in the operation of our business.
- Reduced demand for our products or the use of competing energy products, including alternative energy sources.
- Substantial investment in and development of alternative energy sources, including as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; and other political, economic or diplomatic developments.
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business, including changes resulting from the implementation and interpretation of the Tax Cuts and Jobs Act.
- Competition in the oil and gas exploration and production industry.
- Any limitations on our access to capital or increase in our cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Our inability to execute, or delays in the completion, of any asset dispositions or acquisitions we elect to pursue.
- Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for asset dispositions, or that such approvals may require modification to the terms of the transactions or the operation of our remaining business.
- Potential disruption of our operations as a result of asset dispositions 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.
- Our inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The inability to collect payments when due under our settlement agreement with PDVSA.
- The factors generally described in Item 1A—Risk Factors in our 2017 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the nine months ended September 30, 2018, does not differ materially from that discussed under Item 7A in our 2017 Annual Report on Form 10-K.

Item 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of September 30, 2018, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, Commercial and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance, Commercial and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of September 30, 2018.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. 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 third quarter of 2018 and any material developments with respect to matters previously reported in ConocoPhillips' 2017 Annual Report on Form 10-K. 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 U.S. Securities and Exchange Commission 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 October 2016, after Phillips 66 received a Notice of Intent to Sue from the Sierra Club, Phillips 66 entered into a voluntary settlement with the Illinois Environmental Protection Agency for alleged violations of wastewater requirements at the Wood River Refinery. The settlement involves certain capital projects and payment of $125,000. After the settlement was filed with the Court for final approval, the Sierra Club sought and was granted approval to intervene in the case. The settlement and a first modification were entered by the Court, but the Sierra Club still sought to reopen and challenge the settlement. On February 9, 2018, the Court denied the Sierra Club's motion to reopen the settlement. The Sierra Club did not appeal the Court's denial and the matter is resolved.

Matters Previously Reported—ConocoPhillips
On March 22, 2018, an investigator with the Alberta Energy Regulator issued to ConocoPhillips Canada a preliminary notice recommending that the regulator issue an administrative penalty of $180,000 CAD in connection with an estimated 2,400 barrel condensate release discovered on June 9, 2016. The release was from a transmission pipeline leading from the ConocoPhillips Resthaven gas plant located south of Grande Cache, Alberta. A formal administrative penalty of $180,000 CAD was assessed and paid in the second quarter of 2018.

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 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Item 1A of our 2017 Annual Report on Form 10-K.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

				Millions of Dollars
Period	Total Number of Shares Purchased*	Average Price Paid per Share	Total Number of 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
July 1-31, 2018	4,395,553	$ 70.49	4,395,553	$ 10,418
August 1-31, 2018	2,802,475	71.73	2,802,475	10,217
September 1-30, 2018	5,629,071	74.00	5,629,071	9,801
Total	12,827,099	$ 72.30	12,827,099	$ 9,801

**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, will fully utilize the Board of Directors' existing share repurchase authorization of $6 billion. As a result, our Board has 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 the "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations" section in Risk Factors on pages 20–21 of our 2017 Annual Report on Form 10-K.

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Item 6. **EXHIBITS**

12*	Computation of Ratio of Earnings to Fixed Charges.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.

* Filed herewith.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONOCOPHILLIPS

/s/ Glenda M. Schwarz

Glenda M. Schwarz
Vice President and Controller
(Chief Accounting and Duly Authorized Officer)

October 30, 2018

Exhibit 12

CONOCOPHILLIPS AND CONSOLIDATED SUBSIDIARIES
TOTAL ENTERPRISE

Computation of Ratio of Earnings to Fixed Charges

	Millions of Dollars		
	Nine Months Ended September 30		
		2018	2017
Earnings Available for Fixed Charges			
Income (loss) before income taxes and noncontrolling interests that have not incurred fixed charges	$	**7,263**	(3,983)
Distributions less than equity in earnings of affiliates		**(11)**	(193)
Fixed charges, excluding capitalized interest*		**702**	1,101
	$	**7,954**	(3,075)
Fixed Charges			
Interest and debt expense, excluding capitalized interest	$	**547**	872
Capitalized interest		**132**	86
Interest portion of rental expense		**48**	97
	$	**727**	1,055
Ratio of Earnings to Fixed Charges**		**10.9**	—

**Includes amortization of capitalized interest totaling approximately $107 million in 2018 and $132 million in 2017.*
***Earnings for the nine-month period ended September 30, 2017 were inadequate to cover fixed charges by $4,130 million.*

Exhibit 31.1

CERTIFICATION

I, Ryan M. Lance, certify that:

1. I have reviewed this quarterly report on Form 10-Q of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

October 30, 2018

/s/ Ryan M. Lance

Ryan M. Lance
Chairman and
Chief Executive Officer

CERTIFICATION

I, Don E. Wallette, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

October 30, 2018

/s/ Don E. Wallette, Jr.
Don E. Wallette, Jr.
Executive Vice President, Finance, Commercial and Chief Financial Officer

CERTIFICATIONS PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Quarterly Report of ConocoPhillips (the Company) on Form 10-Q for the period ended September 30, 2018, as filed with the U.S. Securities and Exchange Commission on the date hereof (the Report), each of the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to their knowledge:

(1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

October 30, 2018

/s/ Ryan M. Lance
Ryan M. Lance
Chairman and
Chief Executive Officer

/s/ Don E. Wallette, Jr.
Don E. Wallette, Jr.
Executive Vice President, Finance, Commercial
and Chief Financial Officer