CHEVRON CORP
Form 10-K
February 22, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
OR
o 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 001-00368
Chevron Corporation
(Exact name of registrant as specified in its charter)

Delaware	94-0890210	6001 Bollinger Canyon Road, San Ramon, California 94583-2324
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code (925) 842-1000
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $.75 per share	New York Stock Exchange, Inc.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes þ No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes o No þ
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 þ No o
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes þ No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ
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	þ	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	o
		Emerging growth company	o

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. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes o No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter — $242.2 billion (As of June 29, 2018)

Number of Shares of Common Stock outstanding as of February 11, 2019 — 1,900,062,760

DOCUMENTS INCORPORATED BY REFERENCE

(To The Extent Indicated Herein)

Notice of the 2019 Annual Meeting and 2019 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company's 2019 Annual Meeting of Stockholders (in Part III)

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CAUTIONARY STATEMENT RELEVANT TO FORWARD-LOOKING INFORMATION
FOR THE PURPOSE OF “SAFE HARBOR” PROVISIONS OF THE
PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report on Form 10-K of Chevron Corporation contains forward-looking statements relating to Chevron’s operations that are based on management’s current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words or phrases such as “anticipates,” “expects,” “intends,” “plans,” “targets,” “forecasts,” “projects,” “believes,” “seeks,” “schedules,” “estimates,” “positions,” “pursues,” “may,” “could,” “should,” “will,” “trends,” “guidance,” “focus,” “on schedule,” “on track,” “is slated,” “goals,” “objectives,” “strategies,” “opportunities” and si expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company’s control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.
Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; the company's ability to realize anticipated cost savings and expenditure reductions; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of the company's suppliers, vendors, partners and equity affiliates, particularly during extended periods of low prices for crude oil and natural gas; the inability or failure of the company’s joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company’s operations due to war, accidents, political events, civil unrest, severe weather, cyber threats and terrorist acts, crude oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries, or other natural or human causes beyond the company's control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from other pending or future litigation; the company’s future acquisition or disposition of assets or shares or the delay or failure of such transactions to close based on required closing conditions; the potential for gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, tariffs, sanctions, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; material reductions in corporate liquidity and access to debt markets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; the company's ability to identify and mitigate the risks and hazards inherent in operating in the global energy industry; and the factors set forth under the heading “Risk Factors” on pages 18 through 21 in this report. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

PART I
Item 1. Business
General Development of Business
Summary Description of Chevron
Chevron Corporation,* a Delaware corporation, manages its investments in subsidiaries and affiliates and provides administrative, financial, management and technology support to U.S. and international subsidiaries that engage in integrated energy and chemicals operations. Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation and regasification associated with liquefied natural gas; transporting crude oil by major international oil export pipelines; transporting, storage and marketing of natural gas; and a gas-to-liquids plant. Downstream operations consist primarily of refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lubricant additives.
A list of the company's major subsidiaries is presented on page E-1. As of December 31, 2018, Chevron had approximately 48,600 employees (including about 3,600 service station employees). Approximately 24,800 employees (including about 3,300 service station employees), or 51 percent, were employed in U.S. operations.
Overview of Petroleum Industry
Petroleum industry operations and profitability are influenced by many factors. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. Production levels from the members of the Organization of Petroleum Exporting Countries (OPEC), Russia and the United States are the major factors in determining worldwide supply. Demand for crude oil and its products and for natural gas is largely driven by the conditions of local, national and global economies, although weather patterns and taxation relative to other energy sources also play a significant part. Laws and governmental policies, particularly in the areas of taxation, energy and the environment, affect where and how companies invest, conduct their operations and formulate their products and, in some cases, limit their profits directly.
Strong competition exists in all sectors of the petroleum and petrochemical industries in supplying the energy, fuel and chemical needs of industry and individual consumers. In the upstream business, Chevron competes with fully integrated, major global petroleum companies, as well as independent and national petroleum companies, for the acquisition of crude oil and natural gas leases and other properties and for the equipment and labor required to develop and operate those properties. In its downstream business, Chevron competes with fully integrated, major petroleum companies, as well as independent refining and marketing, transportation and chemicals entities and national petroleum companies in the refining, manufacturing, sale and marketing of fuels, lubricants, additives and petrochemicals.
Operating Environment
Refer to pages 28 through 34 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company's current business environment and outlook.
Chevron's Strategic Direction
Chevron's primary objective is to deliver industry-leading results and superior shareholder value in any business environment. In the upstream, the company's strategy is to deliver industry-leading returns while developing high-value resource opportunities. In the downstream, the company's strategy is to grow earnings across the value chain and make targeted investments to lead the industry in returns.
Information about the company is available on the company's website at www.chevron.com. Information contained on the company's website is not part of this Annual Report on Form 10-K. The company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on the company's website soon after such reports are filed with or furnished to the U.S. Securities and Exchange Commission (SEC). The reports are also available on the SEC's website at www.sec.gov.

* Incorporated in Delaware in 1926 as Standard Oil Company of California, the company adopted the name Chevron Corporation in 1984 and ChevronTexaco Corporation in 2001. In 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. As used in this report, the term “Chevron” and such terms as “the company,” “the corporation,” “our,” “we,” “us” and "its" may refer to Chevron Corporation, one or more of its consolidated subsidiaries, or all of them taken as a whole, but unless stated otherwise they do not include “affiliates” of Chevron — i.e., those companies accounted for by the equity method (generally owned 50 percent or less) or investments accounted for by the cost method. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

Description of Business and Properties

The upstream and downstream activities of the company and its equity affiliates are widely dispersed geographically, with operations and projects* in North America, South America, Europe, Africa, Asia and Australia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2018, and assets as of the end of 2018 and 2017 — for the United States and the company's international geographic areas — are in Note 13 to the Consolidated Financial Statements beginning on page 66. Similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are in Note 14 beginning on page 69 and Note 17 on page 77. Refer to pages 39 and 40 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company's capital and exploratory expenditures.

Upstream

Reserves

Refer to Table V beginning on page 95 for a tabulation of the company's proved net liquids (including crude oil, condensate, natural gas liquids and synthetic oil) and natural gas reserves by geographic area, at the beginning of 2016 and each year-end from 2016 through 2018. Reserves governance, technologies used in establishing proved reserves additions, and major changes to proved reserves by geographic area for the three-year period ended December 31, 2018, are summarized in the discussion for Table V. Discussion is also provided regarding the nature of, status of, and planned future activities associated with the development of proved undeveloped reserves. The company recognizes reserves for projects with various development periods, sometimes exceeding five years. The external factors that impact the duration of a project include scope and complexity, remoteness or adverse operating conditions, infrastructure constraints, and contractual limitations.

At December 31, 2018, 29 percent of the company's net proved oil-equivalent reserves were located in the United States, 20 percent were located in Australia and 18 percent were located in Kazakhstan.

The net proved reserve balances at the end of each of the three years 2016 through 2018 are shown in the following table:

	At December 31		
	2018	2017	2016
Liquids — Millions of barrels			
Consolidated Companies	4,975	4,530	4,131
Affiliated Companies	1,815	2,012	2,197
Total Liquids	6,790	6,542	6,328
Natural Gas — Billions of cubic feet			
Consolidated Companies	28,733	27,514	25,432
Affiliated Companies	2,843	3,222	3,328
Total Natural Gas	31,576	30,736	28,760
Oil-Equivalent — Millions of barrels[1]			
Consolidated Companies	9,764	9,116	8,369
Affiliated Companies	2,289	2,549	2,752
Total Oil-Equivalent	12,053	11,665	11,121

[1] Oil-equivalent conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of crude oil.

* As used in this report, the term "project" may describe new upstream development activity, individual phases in a multiphase development, maintenance activities, certain existing assets, new investments in downstream and chemicals capacity, investments in emerging and sustainable energy activities, and certain other activities. All of these terms are used for convenience only and are not intended as a precise description of the term "project" as it relates to any specific governmental law or regulation.

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Net Production of Liquids and Natural Gas

The following table summarizes the net production of liquids and natural gas for 2018 and 2017 by the company and its affiliates. Worldwide oil-equivalent production of 2.930 million barrels per day in 2018 was up 7 percent from 2017. Production increases from major capital projects, shale and tight properties, and base business were partially offset by normal field declines, the impact of asset sales, and production entitlement effects in several locations. Refer to the "Results of Operations" section beginning on page 32 for a detailed discussion of the factors explaining the 2016 through 2018 changes in production for crude oil and natural gas liquids, and natural gas, and refer to Table V on pages 98 and 99 for information on annual production by geographical region.

			Components of Oil-Equivalent			
Thousands of barrels per day (MBPD)	Oil-Equivalent (MBPD)[1]		Liquids (MBPD)		Natural Gas (MMCFPD)	
Millions of cubic feet per day (MMCFPD)	2018	2017	2018	2017	2018	2017
United States	791	681	618	519	1,034	970
Other Americas						
Argentina	24	23	20	19	24	27
Brazil	11	13	10	12	4	4
Canada[2]	116	98	103	87	79	65
Colombia	14	16	—	—	82	96
Trinidad and Tobago[3]	—	5	—	—	—	29
Total Other Americas	165	155	133	118	189	221
Africa						
Angola	108	112	98	103	59	57
Democratic Republic of the Congo[3]	1	2	1	2	—	1
Nigeria	239	250	200	213	233	223
Republic of Congo	52	38	49	36	14	14
Total Africa	400	402	348	354	306	295
Asia						
Azerbaijan	20	25	18	23	10	11
Bangladesh	112	111	4	4	648	642
China	29	30	16	17	84	81
Indonesia	132	164	113	137	113	163
Kazakhstan	46	55	27	33	120	132
Myanmar	16	19	—	—	98	116
Partitioned Zone[4]	—	—	—	—	—	—
Philippines	26	25	3	3	138	129
Thailand	236	241	66	69	1,022	1,031
Total Asia	617	670	247	286	2,233	2,305
Australia/Oceania						
Australia	426	256	42	27	2,304	1,372
Total Australia/Oceania	426	256	42	27	2,304	1,372
Europe						
Denmark	19	23	12	14	45	53
United Kingdom	65	75	43	50	133	155
Total Europe	84	98	55	64	178	208
Total Consolidated Companies	2,483	2,262	1,443	1,368	6,244	5,371
Affiliates[2,5]	447	466	339	355	645	661

Total Including Affiliates[6]	2,930	2,728	1,782	1,723	6,889	6,032

[1] Oil-equivalent conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of crude oil.

[2] Includes synthetic oil: Canada, net	53	51	53	51	—	—
Venezuelan affiliate, net	24	28	24	28	—	—

[3] Producing fields in Trinidad and Tobago were sold in August 2017. Chevron sold its interest in a concession in the Democratic Republic of Congo in April 2018.
[4] Located between Saudi Arabia and Kuwait. Production has been shut-in since May 2015.
[5] Volumes represent Chevron's share of production by affiliates, including Tengizchevroil in Kazakhstan; Petroboscan and Petropiar in Venezuela; and Angola LNG in Angola.
[6] Volumes include natural gas consumed in operations of 619 million and 565 million cubic feet per day in 2018 and 2017, respectively. Total "as sold" natural gas volumes were 6,270 million and 5,467 million cubic feet per day for 2018 and 2017, respectively.

Production Outlook

The company estimates its average worldwide oil-equivalent production in 2019 will grow 4 to 7 percent compared to 2018, assuming a Brent crude oil price of $60 per barrel and excluding the impact of anticipated 2019 asset sales. This estimate is subject to many factors and uncertainties, as described beginning on page 29. Refer to the “Review of Ongoing Exploration and Production Activities in Key Areas,” beginning on page 8, for a discussion of the company’s major crude oil and natural gas development projects.

Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page 94 for the company’s average sales price per barrel of crude oil, condensate and natural gas liquids and per thousand cubic feet of natural gas produced, and the average production cost per oil-equivalent barrel for 2018, 2017 and 2016.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2018 for the company and its affiliates:

	At December 31, 2018			
	Productive Oil Wells*		Productive Gas Wells*	
	Gross	Net	Gross	Net
United States	39,499	28,594	2,619	1,912
Other Americas	1,067	646	164	98
Africa	1,748	676	21	8
Asia	14,397	12,509	3,697	2,113
Australia/Oceania	560	313	105	29
Europe	324	70	169	35
Total Consolidated Companies	57,595	42,808	6,775	4,195
Affiliates	1,586	554	—	—
Total Including Affiliates	59,181	43,362	6,775	4,195
Multiple completion wells included above	802	525	147	116

* Gross wells represent the total number of wells in which Chevron has an ownership interest. Net wells represent the sum of Chevron's ownership interest in gross wells.

Acreage

At December 31, 2018, the company owned or had under lease or similar agreements undeveloped and developed crude oil and natural gas properties throughout the world. The geographical distribution of the company’s acreage is shown in the following table:

	Undeveloped[2]		Developed		Developed and Undeveloped	
Thousands of acres[1]	Gross	Net	Gross	Net	Gross	Net
United States	3,596	3,441	4,137	2,895	7,733	6,336
Other Americas	14,970	9,663	1,221	277	16,191	9,940
Africa	3,804	1,459	2,237	933	6,041	2,392
Asia	24,368	10,958	1,670	924	26,038	11,882
Australia/Oceania	25,664	17,036	2,002	803	27,666	17,839
Europe	669	300	407	53	1,076	353
Total Consolidated Companies	73,071	42,857	11,674	5,885	84,745	48,742
Affiliates	499	220	305	116	804	336
Total Including Affiliates	73,570	43,077	11,979	6,001	85,549	49,078

[1] Gross acres represent the total number of acres in which Chevron has an ownership interest. Net acres represent the sum of Chevron's ownership interest in gross acres.
[2] The gross undeveloped acres that will expire in 2019, 2020 and 2021 if production is not established by certain required dates are 1,042, 651 and 2,057, respectively.

Delivery Commitments

The company sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Most contracts generally commit the company to sell quantities based on production from specified properties, but some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the United States, the company is contractually committed to deliver 293 billion cubic feet of natural gas to third parties from 2019 through 2021. The company believes it can satisfy these contracts through a combination of equity production from the company’s proved developed U.S. reserves and third-party purchases. These commitments are all based on contracts with indexed pricing terms.

Outside the United States, the company is contractually committed to deliver a total of 2,442 billion cubic feet of natural gas to third parties from 2019 through 2021 from operations in Australia, Colombia, Indonesia and the Philippines. These sales contracts contain variable pricing formulas that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed reserves in these countries.

Development Activities

Refer to Table I on page 91 for details associated with the company's development expenditures and costs of proved property acquisitions for 2018, 2017 and 2016.

The following table summarizes the company's net interest in productive and dry development wells completed in each of the past three years, and the status of the company's development wells drilling at December 31, 2018. A "development well" is a well drilled within the known area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

	Wells Drilling* at 12/31/18		Net Wells Completed					
			2018		2017		2016	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	246	211	509	1	435	4	420	4
Other Americas	22	14	43	—	40	—	45	—
Africa	3	2	8	—	34	—	17	—
Asia	44	17	289	5	246	2	470	6
Australia/Oceania	—	—	1	—	—	—	4	—
Europe	2	—	2	—	4	—	3	—
Total Consolidated Companies	317	244	852	6	759	6	959	10
Affiliates	37	16	39	—	36	—	38	—
Total Including Affiliates	354	260	891	6	795	6	997	10

* Gross wells represent the total number of wells in which Chevron has an ownership interest. Net wells represent the sum of Chevron's ownership interest in gross wells.

Exploration Activities

Refer to Table I on page 91 for detail on the company's exploration expenditures and costs of unproved property acquisitions for 2018, 2017 and 2016.

The following table summarizes the company's net interests in productive and dry exploratory wells completed in each of the last three years, and the number of exploratory wells drilling at December 31, 2018. "Exploratory wells" are wells drilled to find and produce crude oil or natural gas in unknown areas and include delineation and appraisal wells, which are wells drilled to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir or to extend a known reservoir.

	Wells Drilling* at 12/31/18		Net Wells Completed					
			2018		2017		2016	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	5	3	13	2	7	1	4	1

Other Americas	—	—	1	1	—	—	4	—
Africa	1	1	—	—	—	—	1	1
Asia	—	—	1	—	—	—	3	—
Australia/Oceania	—	—	—	—	—	—	—	—
Europe	—	—	—	1	—	1	—	—
Total Consolidated Companies	6	4	15	4	7	2	12	2
Affiliates	—	—	—	—	—	—	—	—
Total Including Affiliates	6	4	15	4	7	2	12	2

* Gross wells represent the total number of wells in which Chevron has an ownership interest. Net wells represent the sum of Chevron's ownership interest in gross wells.

Review of Ongoing Exploration and Production Activities in Key Areas
Chevron has exploration and production activities in most of the world's major hydrocarbon basins. Chevron's 2018 key upstream activities, some of which are also discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations, beginning on page 32, are presented below. The comments include references to "total production" and "net production," which are defined under "Production" in Exhibit 99.1 on page E-7.
The discussion that follows references the status of proved reserves recognition for significant long-lead-time projects not on production as well as for projects recently placed on production. Reserves are not discussed for exploration activities or recent discoveries that have not advanced to a project stage, or for mature areas of production that do not have individual projects requiring significant levels of capital or exploratory investment.
United States
Upstream activities in the United States are primarily located in the midcontinent region, the Gulf of Mexico, California and the Appalachian Basin. Net oil-equivalent production in the United States during 2018 averaged 791,000 barrels per day.
The company's activities in the midcontinent region are primarily in Colorado, New Mexico and Texas. During 2018, net daily production in these areas averaged 198,000 barrels of crude oil, 651 million cubic feet of natural gas and 77,000 barrels of natural gas liquids (NGLs). In 2018, the company divested properties in New Mexico, Oklahoma and Texas. The company is pursuing opportunities to increase development efficiency across the region.
In the Permian Basin of West Texas and southeast New Mexico, the company holds approximately 500,000 and 1,200,000 net acres of shale and tight resources in the Midland and Delaware basins, respectively. This acreage includes multiple stacked formations that enable production from several layers of rock in different geologic zones. Chevron has implemented a factory development strategy in the basin, which utilizes multiwell pads to drill a series of horizontal wells that are completed concurrently using hydraulic fracture stimulation. The company is also applying data analytics and technology on its Permian well information to drive improvements in well targets and performance. In 2018, the company's net daily production in the basin averaged 159,000 barrels of crude oil, 501 million cubic feet of natural gas and 66,000 barrels of NGLs.
During 2018, net daily production in the Gulf of Mexico averaged 186,000 barrels of crude oil, 117 million cubic feet of natural gas and 13,000 barrels of NGLs. Chevron is engaged in various operated and nonoperated exploration, development and production activities in the deepwater Gulf of Mexico. Chevron also holds nonoperated interests in several shelf fields.
The deepwater Jack and St. Malo fields are being jointly developed with a host floating production unit (FPU) located between the two fields. Chevron has a 50 percent interest in the Jack Field and a 51 percent interest in the St. Malo Field. Both fields are company operated. The company has a 40.6 percent interest in the production host facility, which is designed to accommodate production from the Jack/St. Malo development and third-party tiebacks. Total daily production from the Jack and St. Malo fields in 2018 averaged 139,000 barrels of liquids (71,000 net) and 21 million cubic feet of natural gas (11 million net). Additional development opportunities for the Jack and St. Malo fields progressed in 2018. Stage 2 of the development plan was completed with four planned wells on production. Development drilling continued on Stage 3, with two of the three planned wells completed at the end of 2018. Proved reserves have been recognized for these phases. The St. Malo Stage 4 waterflood project entered front-end engineering design (FEED) in 2018 and is expected to reach final investment decision in third quarter 2019. At the end of 2018, proved reserves had not been recognized for this project. The Jack and St. Malo fields have an estimated remaining production life of 30 years.
At the 58 percent-owned and operated deepwater Tahiti Field, net daily production averaged 51,000 barrels of crude oil, 22 million cubic feet of natural gas, and 3,000 barrels of NGLs. Infill drilling continued in 2018 with one new infill well completed. The Tahiti Vertical Expansion project, the next development phase of the Tahiti Field, is developing shallower reservoirs and encompassing four new wells and associated subsea infrastructure. First oil was achieved from three wells in June 2018, and a fourth well is scheduled to come on line in second quarter 2019. The Tahiti Field has an estimated remaining production life of at least 25 years.

The company has a 15.6 percent nonoperated working interest in the deepwater Mad Dog Field. In 2018, net daily production averaged 8,000 barrels of liquids and 1 million cubic feet of natural gas. Project execution continued in 2018 with the next development phase, the Mad Dog 2 Project. This phase of the plan is to develop the southwestern extension of the Mad Dog Field including a new floating production platform with a design capacity of 140,000 barrels of crude oil per day. First oil is expected in 2021. Proved reserves have been recognized for the Mad Dog 2 Project.

The development plan for the 60 percent-owned and operated deepwater Big Foot Project includes a 15-slot drilling and production tension leg platform with water injection facilities and a design capacity of 75,000 barrels of crude oil and 25 million cubic feet of natural gas per day. First oil was achieved in November 2018 and is expected to continue ramp up during 2019. The field has an estimated production life of 35 years.

Chevron holds a 25 percent nonoperated working interest in the Stampede Project located in the Green Canyon area. First oil was achieved in January 2018. In 2018, total daily production averaged 16,000 barrels of crude oil (4,000 net) and 4 million cubic feet of natural gas (1 million net). Production is expected to continue to ramp up until early 2020. The field has an estimated production life of 30 years.

Chevron has owned and operated interests of 55 to 61.3 percent in the blocks containing the Anchor Field. In 2018, the Anchor Field was expanded to include acreage in two additional blocks. FEED activities commenced in 2018 for Stage 1 of the Anchor development, which consists of a seven-well subsea development and semi-submersible floating production unit. The planned facility has a design capacity of 75,000 barrels of crude oil and 28 million cubic feet of natural gas per day. At the end of 2018, proved reserves had not been recognized for this project.

Chevron has a 60 percent-owned and operated interest in the Ballymore field located in the Mississippi Canyon area and a 40 percent nonoperated working interest in the Whale discovery located in the Perdido area. In January 2018, the company announced a significant crude oil discovery at Ballymore. Appraisal activities are underway to evaluate this opportunity and identify a cost-effective development plan. At the Whale discovery, results of the exploration and appraisal wells are being assessed in parallel to progressing cost-effective development options. At the end of 2018, proved reserves had not been recognized for these projects.

In November 2018, Chevron transferred operatorship of the leases under the Tiber and Guadalupe Units following its decision to exit the Tigris project.

In 2018, Chevron added 29 leases to its deepwater portfolio through two gulf-wide lease sales. Chevron also added one additional lease through an asset swap.

In California, the company has significant production in the San Joaquin Valley. In 2018, net daily production averaged 138,000 barrels of crude oil, 25 million cubic feet of natural gas and 400 barrels of NGLs. Chevron sold its nonoperated working interest in the Elk Hills Field in April 2018.

The company holds approximately 428,000 net acres in the Marcellus Shale and 462,000 net acres in the Utica Shale, primarily located in southwestern Pennsylvania, the West Virginia panhandle and eastern Ohio. During 2018, net daily production in these areas averaged 240 million cubic feet of natural gas, 4,000 barrels of NGLs and 1,000 barrels of condensate. Chevron has implemented a factory development strategy, which enables future co-development of the Marcellus and Utica shales from the same pads in stacked play locations.

Other Americas

“Other Americas” includes Argentina, Brazil, Canada, Colombia, Mexico, Suriname and Venezuela. Net oil-equivalent production from these countries averaged 209,000 barrels per day during 2018.

Canada Upstream activities in Canada are concentrated in Alberta, British Columbia and the offshore Atlantic region. The company also has discovered resource interests in the Beaufort Sea region of the Northwest Territories. Net oil-equivalent production during 2018 averaged 116,000 barrels per day, composed of 50,000 barrels of crude oil, 79 million cubic feet of natural gas and 53,000 barrels of synthetic oil from oil sands.

Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field and a 23.7 percent nonoperated working interest in the unitized Hibernia Southern Extension areas offshore Atlantic Canada.

The company holds a 29.6 percent nonoperated working interest in the heavy oil Hebron Field, also offshore Atlantic Canada. Total daily crude production averaged 60,000 barrels (18,000 net) in 2018 and is expected to continue ramp up during 2019. The field has an expected economic life of 30 years.

The company holds a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP) in Alberta. Oil sands are mined from both the Muskeg River and the Jackpine mines, and bitumen is extracted from the oil sands and upgraded into synthetic oil. Carbon dioxide emissions from the upgrade process are reduced by the Quest carbon capture and storage facilities.

The company holds approximately 215,000 net acres in the Duvernay Shale in Alberta. Chevron has a 70 percent-owned and operated interest in most of the Duvernay acreage. Chevron is applying learnings from other company-owned shale assets to lower development costs. A total of 122 wells have been tied into production facilities by early 2019. In 2018, net daily production averaged 9,000 barrels of crude oil and 54 million cubic feet of natural gas.

Chevron holds a 50 percent-owned and operated interest in Flemish Pass Basin Block EL 1138 with 339,000 net acres. The company relinquished its interest in blocks EL 1125 and EL 1126 in 2018.

Chevron holds a 50 percent-owned and operated interest in the proposed Kitimat LNG and Pacific Trail Pipeline projects and a 50 percent owned and operated interest in 290,000 net acres in the Liard and Horn River shale gas basins in British Columbia. The horizontal appraisal drilling program progressed during 2018. The Kitimat LNG Project is planned to include a two-train LNG facility and has a 10.0 million-metric-ton-per-year export license. The total production capacity for the project is expected to be 1.6 billion cubic feet of natural gas per day. Spending is being paced until LNG market conditions and reductions in project costs are sufficient to support the development of this project. At the end of 2018, proved reserves had not been recognized for this project.

Mexico The company owns and operates a 33.3 percent interest in Block 3 in the Perdido area of the Gulf of Mexico covering 139,000 net acres. Seismic reprocessing activities continued in 2018. Chevron also holds a 37.5 percent-owned and operated interest in Block 22 in the deepwater Cuenca Salina area of the Gulf of Mexico covering 267,000 net acres. In October 2018, an environmental baseline study was completed. Seismic data reprocessing activities have extended into 2019.

Argentina Chevron holds a 50 percent nonoperated interest in the Loma Campana and Narambuena concessions in the Vaca Muerta Shale covering 73,000 net acres. Chevron also holds an 85 percent-owned and operated interest in the El Trapial concession covering 94,000 net acres with both conventional production and Vaca Muerta Shale potential. Net oil-equivalent production in 2018 averaged 24,000 barrels per day, composed of 20,000 barrels of crude oil and 24 million cubic feet of natural gas. Nonoperated development activities continued in 2018 at the Loma Campana concession in the Vaca Muerta Shale. During 2018, the drilling program continued with 32 horizontal wells drilled. This concession expires in 2048.

The company utilizes waterflood operations to mitigate declines at the operated El Trapial Field and continues to evaluate the potential of the Vaca Muerta Shale. Chevron initiated a shale appraisal drilling program in November 2018. The El Trapial concession expires in 2032.

Evaluation of the nonoperated Narambuena Block continued in 2018, with appraisal activity planned for 2019.

Chevron conducted an environmental review on the 90 percent owned and operated Loma del Molle Norte Block adjacent to the El Trapial concession, which covers 43,000 net acres.

Brazil In January 2019, Chevron signed an agreement for the sale of its 51.7 percent interest in the Frade field and its 50 percent-owned and operated interest in Block CE-M715. The sale is expected to close in 2019. Net oil-equivalent production in 2018 averaged 11,000 barrels per day, composed of 10,000 barrels of crude oil and 4 million cubic feet of natural gas.

Additionally, Chevron holds a 37.5 percent nonoperated interest in the Papa-Terra field that expires in 2032.

In 2018, Chevron won six deepwater blocks in the prolific Brazil pre-salt trend within the Campos and Santos basins. The company holds between 30 to 50 percent of both operated and nonoperated interest in the six new blocks. The six blocks cover 470,000 net acres.

Colombia The company operates the offshore Chuchupa and onshore Ballena natural gas fields and receives 43 percent of the production for the remaining life of each field. Net daily production in 2018 averaged 82 million cubic feet of natural gas.

Suriname Chevron holds a 33.3 percent and a 50 percent nonoperated working interest in deepwater Blocks 42 and 45 offshore Suriname, respectively. Two exploratory wells were drilled in Blocks 42 and 45 in 2018, with additional exploratory drilling activity planned.

Venezuela Chevron's production activities in Venezuela are located in western Venezuela and the Orinoco Belt. Net oil-equivalent production during 2018 averaged 44,000 barrels per day, composed of 42,000 barrels of crude oil and 9 million cubic feet of natural gas.
Chevron has a 30 percent interest in the Petropiar affiliate that operates the heavy oil Huyapari Field, formerly known as Hamaca. The production and upgrading project is located in Venezuela’s Orinoco Belt under an agreement expiring in 2033.

Petropiar drilled 64 development wells in 2018. Chevron also holds a 39.2 percent interest in the Petroboscan affiliate that operates the Boscan Field in western Venezuela and a 25.2 percent interest in the Petroindependiente affiliate that operates the LL-652 Field in Lake Maracaibo, both of which are under agreements expiring in 2026. Petroboscan drilled 21 development wells in 2018.

Chevron also holds a 34 percent interest in the Petroindependencia affiliate, which includes the Carabobo 3 heavy oil project located within the Orinoco Belt. The Petroindependencia contract expires in 2035.

Greenland Chevron relinquished its 29.2 percent-owned and operated interest in two exploration blocks off the northeast coast of Greenland in 2018.

Africa

In Africa, the company is engaged in upstream activities in Angola, Nigeria and Republic of Congo. Net oil-equivalent production averaged 450,000 barrels per day during 2018 in this region.

Angola The company operates and holds a 39.2 percent interest in Block 0, a concession adjacent to the Cabinda coastline, and a 31 percent interest in a production-sharing contract (PSC) for deepwater Block 14. The concession for Block 0 extends through 2030 and the development and production rights for the various producing fields in Block 14 expire between 2023 and 2031. During 2018, net production averaged 107,000 barrels of liquids and 308 million cubic feet of natural gas per day.

The Mafumeira Sul development achieved its first liquefied petroleum gas (LPG) export in January 2018. Ramp-up continued at the main production facility with total daily production in 2018 averaging 52,000 barrels of liquids (17,000 net) and 147 million cubic feet of natural gas (57 million net), exported to the Angola LNG Plant. Additionally, six new wells were drilled in 2018.

Chevron has a 36.4 percent interest in Angola LNG Limited, which operates an onshore natural gas liquefaction plant in Soyo, Angola. The plant has the capacity to process 1.1 billion cubic feet of natural gas per day. This is the world's first LNG plant supplied with associated gas, where the natural gas is a byproduct of crude oil production. Feedstock for the plant originates from multiple fields and operators. Total daily production in 2018 averaged 685 million cubic feet of natural gas (249 million net) and 23,000 barrels of NGLs (8,500 net).

Angola-Republic of Congo Joint Development Area Chevron operates and holds a 31.3 percent interest in the Lianzi Unitization Zone, located in an area shared equally by Angola and the Republic of Congo. Production from Lianzi is reflected in the totals for Angola and the Republic of Congo.

Republic of Congo Chevron has a 31.5 percent nonoperated working interest in the offshore Haute Mer permit areas (Nkossa and Moho-Bilondo). The licenses for Nkossa and Moho-Bilondo expire in 2027 and 2030, respectively. Additionally, the company has a 20.4 percent nonoperated working interest in the offshore Haute Mer B permit area. Average net daily production in 2018 was 49,000 barrels of liquids.

Two exploration wells were drilled in 2018, with one in the Moho Bilondo area and a second in the Haute Mer B area.

Nigeria Chevron operates and holds a 40 percent interest in eight concessions in the onshore and near-offshore regions of the Niger Delta. The company also holds acreage positions in three operated and six nonoperated deepwater blocks, with working interests ranging from 20 to 100 percent. In 2018, the company’s net oil-equivalent production in Nigeria averaged 239,000 barrels per day, composed of 194,000 barrels of crude oil, 233 million cubic feet of natural gas and 6,000 barrels of LPG.

Chevron completed the final well in its infill drilling program in the Niger Delta in first quarter 2019. Further infill drilling programs are beginning in 2019. The company is the operator of the Escravos Gas Plant (EGP) with a total processing capacity of 680 million cubic feet per day of natural gas and LPG and condensate export capacity of 58,000 barrels per day. The company is also the operator of the 33,000-barrel-per-day Escravos gas-to-liquids facility.

The 40 percent-owned and operated Sonam Field Development Project is designed to process natural gas through the EGP facilities and deliver it to the domestic gas market. Net daily production in 2018 averaged 10,000 barrels of liquids and 80 million cubic feet of natural gas.

In addition, the company holds a 36.7 percent interest in the West African Gas Pipeline Company Limited affiliate, which supplies Nigerian natural gas to customers in Benin, Ghana and Togo.

Chevron operates and holds a 67.3 percent interest in the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128. The original Agbami development scope has been completed (Agbami 1, 2 and 3). Infill drilling continued in 2018 to further offset field decline, with additional infill drilling planned for 2019. The leases that contain the Agbami Field expire in 2023 and 2024. Additionally, Chevron holds a 30 percent nonoperated working interest in the Usan Field.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in OML 118 share a common geologic structure and are planned to be jointly developed. Chevron holds a 16.6 percent nonoperated working interest in the unitized area. The development plan involves subsea wells tied back to a floating production, storage and offloading vessel. Work continues to progress towards a final investment decision. At the end of 2018, no proved reserves were recognized for this project.
In deepwater exploration, Chevron operates and holds a 55 percent interest in the deepwater Nsiko discoveries in OML 140. A 3-D seismic acquisition program is planned for OML 140 and the adjacent OML 132 in 2019. Chevron also holds a 30 percent nonoperated working interest in OML 138, which includes the Usan Field and several satellite discoveries, and a 27 percent interest in adjacent licenses OML 139 and OML 154. The company plans to continue to evaluate development options for the multiple discoveries in the Usan area, including the Owowo Field, which straddles OML 139 and Oil Prospecting License (OPL) 223.
Democratic Republic of the Congo Chevron sold its 17.7 percent nonoperated working interest in an offshore concession in April 2018.
Liberia Chevron surrendered its 45 percent interest in Block LB-14 off the coast of Liberia in July 2018.
Morocco The company surrendered its interest in the Cap Cantin Deep and Cap Walidia Deep acreage in September 2018.
Asia
In Asia, the company is engaged in upstream activities in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, the Kurdistan Region of Iraq, Myanmar, the Partitioned Zone located between Saudi Arabia and Kuwait, the Philippines, Russia and Thailand. During 2018, net oil-equivalent production averaged 970,000 barrels per day in this region.
Azerbaijan Chevron holds a 9.6 percent nonoperated interest in the Azerbaijan International Operating Company (AIOC) and the crude oil production from the Azeri-Chirag-Gunashli (ACG) fields. AIOC operations are conducted under a PSC that expires in 2049. Net oil-equivalent production in 2018 averaged 20,000 barrels per day, composed of 18,000 barrels of crude oil and 10 million cubic feet of natural gas.
Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline affiliate, which transports the majority of ACG production from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities at Ceyhan, Turkey. The BTC pipeline has a capacity of 1 million barrels per day. Another production export route for crude oil is the Western Route Export Pipeline (WREP), which is operated by AIOC. During 2018, WREP transported approximately 76,000 barrels per day from Baku, Azerbaijan, to a marine terminal at Supsa, Georgia, on the Black Sea.
In 2018, Chevron announced its intent to market its share in AIOC and the BTC pipeline affiliate.
Kazakhstan Chevron has a 50 percent interest in the Tengizchevroil (TCO) affiliate and an 18 percent nonoperated working interest in the Karachaganak Field. Net oil-equivalent production in 2018 averaged 399,000 barrels per day, composed of 315,500 barrels of liquids and 507 million cubic feet of natural gas.
TCO is developing the Tengiz and Korolev crude oil fields in western Kazakhstan under a concession agreement that expires in 2033. Net daily production in 2018 from these fields averaged 269,000 barrels of crude oil, 387 million cubic feet of natural gas and 19,500 barrels of NGLs. All of TCO’s crude oil production was exported through the Caspian Pipeline Consortium (CPC) pipeline.
The Future Growth and Wellhead Pressure Management Project (FGP/WPMP) at Tengiz is being managed as a single integrated project. The FGP is designed to increase total daily production by about 260,000 barrels of crude oil and to expand the utilization of sour gas injection technology proven in existing operations to increase ultimate recovery from the reservoir. The WPMP is designed to maintain production levels in existing plants as reservoir pressure declines. Project execution advanced in 2018 with completion of construction and operational readiness of the Cargo Transportation Route facility (CaTRo). During 2018, CaTRo received 28 pre-assembled racks and 12 were successfully set on foundation. Additionally, a major milestone was achieved in September 2018 when the first modular unit of the processing plant arrived at the construction site in Kazakhstan. This module was successfully restacked by the end of the year, along with two gas turbine generator modules. First oil is planned for 2022. Proved

reserves have been recognized for the FGP/WPMP.
The Capacity and Reliability Project is designed to reduce facility bottlenecks and increase plant capacity and reliability at Tengiz. The project was completed in second quarter 2018.

The Karachaganak Field is located in northwest Kazakhstan, and operations are conducted under a PSC that expires in 2038. During 2018, net daily production averaged 27,000 barrels of liquids and 120 million cubic feet of natural gas. Most of the exported liquids were transported through the CPC pipeline. Work continues to identify the optimal scope for the future expansion of the field. At the end of 2018, proved reserves had not been recognized for a future expansion.

Kazakhstan/Russia Chevron has a 15 percent interest in the CPC. During 2018, CPC transported an average of 1.3 million barrels of crude oil per day, composed of 1.2 million barrels per day from Kazakhstan and 147,000 barrels per day from Russia.

Bangladesh Chevron operates and holds a 100 percent interest in Block 12 (Bibiyana Field) and Blocks 13 and 14 (Jalalabad and Moulavi Bazar fields). The rights to produce from Jalalabad expire in 2030, from Moulavi Bazar in 2033 and from Bibiyana in 2034. Net oil-equivalent production in 2018 averaged 112,000 barrels per day, composed of 648 million cubic feet of natural gas and 4,000 barrels of condensate.

Myanmar Chevron has a 28.3 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana, Badamyar and Sein fields, within Blocks M5 and M6, in the Andaman Sea. The PSC expires in 2028. The company also has a 28.3 percent nonoperated interest in a pipeline company that transports natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. Net natural gas production in 2018 averaged 98 million cubic feet per day.

Chevron also holds a 55 percent-owned and operated interest in Blocks AD3 and A5. Seismic processing and interpretation continued in 2018.

Thailand Chevron holds operated interests in the Pattani Basin, located in the Gulf of Thailand, with ownership ranging from 35 percent to 80 percent. Concessions for producing areas within this basin expire between 2022 and 2035. Chevron also has a 16 percent nonoperated working interest in the Arthit Field located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040. Net oil-equivalent production in 2018 averaged 236,000 barrels per day, composed of 66,000 barrels of crude oil and condensate and 1.0 billion cubic feet of natural gas.

In the Pattani Basin, the 35 percent-owned and operated Ubon Project in Block 12/27 completed FEED on a Central Processing Platform with a floating, storage and offloading vessel for oil export. At the end of 2018, proved reserves had not been recognized for this project. Chevron also holds ownership ranging from 70 to 80 percent of the Erawan concession, which expires in 2022. Following the concession expiration, Chevron expects to transfer the Erawan operations to the Government of Thailand. Erawan concession's net average daily production in 2018 was 46,000 barrels of crude oil and condensate and 800 million cubic feet of natural gas.

Chevron holds between 30 and 80 percent operated and nonoperated working interests in the Thailand-Cambodia overlapping claim area that are inactive, pending resolution of border issues between Thailand and Cambodia.

China Chevron has operated and nonoperated working interests in several areas in China. The company’s net daily production in 2018 averaged 16,000 barrels of crude oil and 84 million cubic feet of natural gas.

The company operates the 49 percent-owned Chuandongbei Project, located onshore in the Sichuan Basin. The Xuanhan Gas Plant has three gas processing trains with a design outlet capacity of 258 million cubic feet per day. Total daily production in 2018 averaged 183 million cubic feet of natural gas (84 million net).

The company also has nonoperated working interests of 24.5 percent in the QHD 32-6 Block and 16.2 percent in Block 11/19 in the Bohai Bay, and 32.7 percent in Block 16/19 in the Pearl River Mouth Basin. The PSCs for these producing assets expire between 2022 and 2028.

Philippines The company holds a 45 percent nonoperated working interest in the offshore Malampaya natural gas field. Net oil-equivalent production in 2018 averaged 26,000 barrels per day, composed of 138 million cubic feet of natural gas and 3,000 barrels of condensate. The concession expires in 2024.

Indonesia Chevron holds working interests through various PSCs in Indonesia. In Sumatra, the company holds a 100 percent-owned and operated interest in the Rokan PSC, which expires in 2021. Chevron also operates three PSCs in the Kutei Basin (Makassar Strait, Rapak and Ganal), located offshore eastern Kalimantan. These interests range from

62 to 72 percent. Net oil-equivalent production in 2018 averaged 132,000 barrels per day, composed of 113,000 barrels of liquids and 113 million cubic feet of natural gas. In fourth quarter 2018, Chevron relinquished the expired East Kalimantan PSC.

There are two deepwater natural gas development projects in the Kutei Basin progressing under a single plan of development. Collectively, these projects are referred to as the Indonesia Deepwater Development and the company's interest is 62 percent. One of these projects, Bangka, includes a two-well subsea tieback to the West Seno FPU, and is producing.

The other project, Gendalo-Gehem, has a planned design capacity of 920 million cubic feet of natural gas and 30,000 barrels of condensate per day. A revised plan of development was submitted to the Government of Indonesia for approval in 2018. Gas from the project is expected to be marketed for both domestic sale and LNG export after liquefaction at the state-owned

Bontang LNG plant in East Kalimantan. The company continues to work toward a final investment decision, subject to economic competitiveness, timing of government approvals, including extension of the associated PSCs, and securing new LNG sales contracts. At the end of 2018, proved reserves had not been recognized for this project.
Kurdistan Region of Iraq The company operates and holds 80 percent contractor interests in the Sarta and Qara Dagh PSCs. In July 2018, the company entered into an agreement with the Kurdistan Regional Government for the Qara Dagh block, which allows the company to continue evaluating exploration opportunities through October 2020. The company has drilled two exploration wells and an appraisal well in the Sarta block and evaluation of these resource opportunities is ongoing. The Sarta PSC expires in 2047. Chevron signed an agreement to farm out a 30 percent interest in the Sarta block and a 40 percent interest in the Qara Dagh block, which is expected to close in 2019, pending government approval.
Partitioned Zone Chevron holds a concession to operate the Kingdom of Saudi Arabia's 50 percent interest in the hydrocarbon resources in the onshore area of the Partitioned Zone between Saudi Arabia and Kuwait. The concession expires in 2039. Beginning in May 2015, production in the Partitioned Zone was shut in as a result of continued difficulties in securing work and equipment permits. As of early 2019, production remains shut in, and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait and the acquisition of necessary permits.
Processing and interpretation of the 3-D seismic survey, which was acquired in 2016 and covers the entire onshore Partitioned Zone, is complete. Work is underway to mature several exploration prospects.
Australia/Oceania
In Australia/Oceania, the company is engaged in upstream activities in Australia and New Zealand. During 2018 net oil-equivalent production averaged 426,000 barrels per day, all from Australia.
Australia Upstream activities in Australia are concentrated offshore Western Australia, where the company is the operator of two major LNG projects, Gorgon and Wheatstone, and has a nonoperated working interest in the North West Shelf (NWS) Venture and exploration acreage in the Browse Basin and the Carnarvon Basin. The company also holds exploration acreage in the Bight Basin offshore South Australia. The company's relinquishment of the Bright Basin acreage is pending government approval. During 2018, the company's net daily production averaged 42,000 barrels of liquids and 2.3 billion cubic feet of natural gas.
Chevron holds a 47.3 percent interest in and is the operator of the Gorgon Project, which includes the development of the Gorgon and Jansz-Io fields. The project includes a three-train, 15.6 million-metric-ton-per-year LNG facility, a domestic gas plant, and a carbon dioxide capture and injection facility with first injection expected in 2019. The facilities are located on Barrow Island. In April 2018, the company reached final investment decision on Stage 2 of Gorgon which will include 11 new wells in the Gorgon and Jansz-Io fields and additional subsea infrastructure. Drilling of the new wells is expected to begin in second quarter 2019. Total daily production from all three trains in 2018 averaged 18,000 barrels of condensate (8,500 barrels net) and 2.6 billion cubic feet of natural gas (1.2 billion net). The project's estimated economic life exceeds 40 years.
Chevron holds an 80.2 percent interest in the offshore licenses and a 64.1 percent interest in the LNG facilities associated with the Wheatstone Project. The project includes the development of the Wheatstone and Iago fields, a two-train, 8.9 million-metric-ton-per-year LNG facility, and a domestic gas plant. The onshore facilities are located at Ashburton North on the coast of Western Australia. The total production capacity for the Wheatstone and Iago fields and nearby third-party fields is expected to be approximately 1.6 billion cubic feet of natural gas and 30,000 barrels of condensate per day. LNG Train 2 start-up and first cargo were achieved in June 2018. Total daily production averaged 16,000 barrels of condensate (12,800 net) and 801 million cubic feet of natural gas (642 million net) in 2018. The project's estimated economic life exceeds 30 years.
Chevron has a 16.7 percent nonoperated working interest in the NWS Venture in Western Australia.
Chevron holds 50 percent-owned and operated interests in four exploration permits in the northern Carnarvon Basin. Chevron continued to evaluate exploration potential in the Carnarvon Basin during 2018.

The company holds nonoperated working interests ranging from 24.8 percent to 50 percent in three exploration blocks in the Browse Basin.

Chevron has a 100 percent-owned and operated interest in the Clio, Acme and Acme West fields. The company is collaborating with other Carnarvon Basin participants to assess the opportunity of Clio Acme being developed through shared utilization of existing infrastructure.

New Zealand Chevron holds a 50 percent interest and operates three deepwater exploration permits in the offshore Pegasus and East Coast basins. Seismic processing and interpretation continued in 2018.

Europe
In Europe, the company is engaged in upstream activities in Denmark and the United Kingdom. Net oil-equivalent production averaged 84,000 barrels per day during 2018.
Denmark Chevron signed an agreement to sell its 12 percent nonoperated working interest in the Danish Underground Consortium in September 2018. The sale is expected to close in 2019, pending regulatory approval.
United Kingdom The company's net oil-equivalent production in 2018 averaged 65,000 barrels per day, composed of 43,000 barrels of liquids and 133 million cubic feet of natural gas. In 2018, Chevron announced its intent to market its Central North Sea assets, including Captain.
The Captain Enhanced Oil Recovery (EOR) Project is the next development phase of the Captain Field, which is designed to increase field recovery by injecting a polymer/water mixture into the Captain reservoir. Stage 1 of the project is an expansion of the existing polymer injection system on the wellhead production platform that includes six new polymer injection wells and modifications to the platform facilities. Proved reserves have been recognized for Stage 1 of this project. During 2018, construction continued to progress on Captain EOR Stage 2, which involves subsea expansion of the technology. At the end of 2018, proved reserves had not been recognized for Stage 2 of the project.
Chevron has a 19.4 percent nonoperated working interest in the Clair Ridge Project, located west of the Shetland Islands. The project is the second development phase of the Clair Field. The design capacity of the project is 120,000 barrels of crude oil and 100 million cubic feet of natural gas per day. First production was achieved in November 2018. The Clair Field has an estimated production life extending until 2050.
In January 2019, Chevron sold its 40 percent operated working interest in the Rosebank Field.
Norway In November 2018, the company divested its 20 percent nonoperated working interest in exploration Block PL 859, located in the Barents Sea.
Sales of Natural Gas and Natural Gas Liquids
The company sells natural gas and natural gas liquids (NGLs) from its producing operations under a variety of contractual arrangements. In addition, the company also makes third-party purchases and sales of natural gas and NGLs in connection with its supply and trading activities.
During 2018, U.S. and international sales of natural gas averaged 3.5 billion and 5.6 billion cubic feet per day, respectively, which includes the company's share of equity affiliates' sales. Outside the United States, substantially all of the natural gas sales from the company's producing interests are from operations in Angola, Australia, Bangladesh, Europe, Kazakhstan, Indonesia, Latin America, Myanmar, Nigeria, the Philippines and Thailand.
U.S. and international sales of NGLs averaged 184,000 and 96,000 barrels per day, respectively, in 2018. Substantially all of the international sales of NGLs from the company's producing interests are from operations in Angola, Australia, Canada, Indonesia, Nigeria and the United Kingdom.
Refer to "Selected Operating Data," on page 37 in Management's Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company's sales volumes of natural gas and natural gas liquids. Refer also to "Delivery Commitments" beginning on page 6 for information related to the company's delivery commitments for the sale of crude oil and natural gas.
Downstream
Refining Operations
At the end of 2018, the company had a refining network capable of processing nearly 1.6 million barrels of crude oil per day. Operable capacity at December 31, 2018, and daily refinery inputs for 2016 through 2018 for the company and affiliate refineries are summarized in the table on the next page.
Average crude oil distillation capacity utilization was 93 percent in 2018 and 2017. At the U.S. refineries, crude oil distillation capacity utilization averaged 97 percent in 2018, compared with 98 percent in 2017. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 70 percent and 71 percent of Chevron's U.S. refinery inputs in 2018 and 2017, respectively.

In the United States, the company continued work on projects to improve refinery flexibility and reliability. At the Richmond refinery in California, first production commenced at the new hydrogen plant in November 2018 and full operation of the

project is expected in 2019. At the refinery in Salt Lake City, Utah, construction continues for the alkylation retrofit project. Project start-up is expected in 2020. In January 2019, the company signed an agreement to acquire a refinery in Pasadena, Texas.

Outside the United States, the company has three large refineries in South Korea, Singapore and Thailand. The Singapore Refining Company (SRC), a 50 percent-owned joint venture, processes up to 276,000 barrels of crude per day and manufactures a wide range of petroleum products. The company continues to progress evaluation and development of upgrading projects to convert low-value products into higher-value products. The 50 percent-owned, GS Caltex operated, Yeosu Refinery in South Korea remains one of the world's largest and is targeted for additional investment with the addition of olefins production capacity. The company's 60.6 percent-owned refinery in Map Ta Phut, Thailand, continues to supply high-quality petroleum products through the Caltex brand in the Thailand market. In September 2018, the company completed the sale of its interest in the Cape Town refinery in South Africa.

Petroleum Refineries: Locations, Capacities and Inputs

Capacities and inputs in thousands of barrels per day		December 31, 2018		Refinery Inputs		
Locations		Number	Operable Capacity	2018	2017	2016
Pascagoula	Mississippi	1	351	332	349	355
El Segundo	California	1	269	273	251	267
Richmond	California	1	257	249	248	188
Kapolei[1]	Hawaii	—	—	—	—	37
Salt Lake City	Utah	1	55	51	53	53
Total Consolidated Companies — United States		4	932	905	901	900
Map Ta Phut	Thailand	1	157	160	152	162
Cape Town[2]	South Africa	—	—	49	68	78
Burnaby, B.C.[3]	Canada	—	—	—	40	51
Total Consolidated Companies — International		1	157	209	260	291
Affiliates	Various Locations	3	538	494	500	497
Total Including Affiliates — International		4	695	703	760	788
Total Including Affiliates — Worldwide		8	1,627	1,608	1,661	1,688

[1] In November 2016, the company sold the Hawaii refinery.
[2] In September 2018, the company sold its interest in the Cape Town refinery.
[3] In September 2017, the company sold the Burnaby, B.C. refinery.

Marketing Operations

The company markets petroleum products under the principal brands of “Chevron,” “Texaco” and “Caltex” throughout many parts of the world. The following table identifies the company’s and affiliates’ refined products sales volumes, excluding intercompany sales, for the three years ended December 31, 2018.

Refined Products Sales Volumes

Thousands of barrels per day	2018	2017	2016
United States			
Gasoline	627	625	631
Jet Fuel	255	242	242
Diesel/Gas Oil	188	179	182

Residual Fuel Oil	48	48	59
Other Petroleum Products[1]	100	103	99
Total United States	1,218	1,197	1,213
International[2]			
Gasoline	336	365	382
Jet Fuel	276	274	261
Diesel/Gas Oil	446	490	468
Residual Fuel Oil	177	162	144
Other Petroleum Products[1]	202	202	207
Total International	1,437	1,493	1,462
Total Worldwide[2]	2,655	2,690	2,675
[1] Principally naphtha, lubricants, asphalt and coke.			
[2] Includes share of affiliates' sales:	373	366	377

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In the United States, the company markets under the Chevron and Texaco brands. At year-end 2018, the company supplied directly or through retailers and marketers approximately 7,900 Chevron- and Texaco- branded service stations, primarily in the southern and western states. Approximately 310 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 5,000 branded service stations, including affiliates. The company markets in Latin America using the Texaco brand. In 2018, Chevron continued to grow, expanding to 135 branded stations in northwestern Mexico at the end of the year. In the Asia-Pacific region and the Middle East, the company uses the Caltex brand. The company also operates through affiliates under various brand names. In South Korea, the company operates through its 50 percent-owned affiliate, GS Caltex. In September 2018, the company completed the sale of its marketing and lubricants businesses in southern Africa and Botswana.

Chevron markets commercial aviation fuel at approximately 90 airports worldwide. The company also markets an extensive line of lubricant and coolant products under the product names Havoline, Delo, Ursa, Meropa, Rando, Clarity and Taro in the United States and worldwide under the three brands: Chevron, Texaco and Caltex.

Chemicals Operations

Chevron Oronite Company develops, manufactures and markets performance additives for lubricating oils and fuels and conducts research and development for additive component and blended packages. At the end of 2018, the company manufactured, blended or conducted research at 10 locations around the world. In June 2018, a final investment decision was reached for a lubricant additive blending and shipping plant in Ningbo, China. Commercial production is anticipated to begin in 2021.

Chevron owns a 50 percent interest in its Chevron Phillips Chemical Company LLC (CPChem) affiliate. CPChem produces olefins, polyolefins and alpha olefins and is a supplier of aromatics and polyethylene pipe, in addition to participating in the specialty chemical and specialty plastics markets. At the end of 2018, CPChem owned or had joint-venture interests in 28 manufacturing facilities and two research and development centers around the world.

In March 2018, CPChem commenced operations of a new ethane cracker with an annual design capacity of 1.5 million metric tons of ethylene located at the Cedar Bayou facility, and reached design capacity during second quarter 2018.

Chevron also maintains a role in the petrochemical business through the operations of GS Caltex, a 50 percent-owned affiliate. GS Caltex manufactures aromatics, including benzene, toluene and xylene. These base chemicals are used to produce a range of products, including adhesives, plastics and textile fibers. GS Caltex also produces polypropylene, which is used to make automotive and home appliance parts, food packaging, laboratory equipment and textiles.

GS Caltex expects to reach a final investment decision in first quarter 2019 to build an olefins mixed-feed cracker and polyethylene unit within the existing refining and aromatics facilities in Yeosu, South Korea.

Transportation

Pipelines Chevron owns and operates a network of crude oil, natural gas and product pipelines and other infrastructure assets in the United States. In addition, Chevron operates pipelines for its 50 percent-owned CPChem affiliate. The company also has direct and indirect interests in other U.S. and international pipelines.

Refer to pages 11 through 13 in the Upstream section for information on the West African Gas Pipeline, the Baku-Tbilisi-Ceyhan Pipeline, the Western Route Export Pipeline and the Caspian Pipeline Consortium.

Shipping The company's marine fleet includes both U.S. and foreign flagged vessels. The operated fleet consists of conventional crude tankers, product carriers, and LNG carriers. These vessels transport crude oil, LNG, refined products and feedstocks in support of the company's global upstream and downstream businesses.

Other Businesses

Research and Technology Chevron's energy technology organization supports upstream and downstream businesses. The company conducts research, develops and qualifies technology, and provides technical services and competency development. The disciplines cover earth sciences, reservoir and production engineering, drilling and completions, facilities engineering, manufacturing, process technology, catalysis, technical computing and health, environment and

safety.

Chevron's information technology organization integrates computing, telecommunications, data management, cybersecurity and network technology to provide a digital infrastructure to enable Chevron’s global operations and business processes.

In 2018, Chevron joined the Oil and Gas Climate Initiative and separately launched the Chevron Future Energy Fund. Both initiatives invest in technology designed to economically lower emissions.

Chevron's technology ventures company supports Chevron's upstream and downstream businesses by bridging the gap between business unit needs and emerging technology solutions developed externally in areas of emerging materials, water management, information technology, power systems and production enhancement.
Some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, and ultimate technical or commercial successes are not certain. Refer to Note 26 on page 89 for a summary of the company's research and development expenses.
Environmental Protection The company designs, operates and maintains its facilities to avoid potential spills or leaks and to minimize the impact of those that may occur. Chevron requires its facilities and operations to have operating standards and processes and emergency response plans that address significant risks identified through site-specific risk and impact assessments. Chevron also requires that sufficient resources be available to execute these plans. In the unlikely event that a major spill or leak occurs, Chevron also maintains a Worldwide Emergency Response Team comprised of employees who are trained in various aspects of emergency response, including post-incident remediation.
To complement the company's capabilities, Chevron maintains active membership in international oil spill response cooperatives, including the Marine Spill Response Corporation, which operates in U.S. territorial waters, and Oil Spill Response, Ltd., which operates globally. The company is a founding member of the Marine Well Containment Company, whose primary mission is to expediently deploy containment equipment and systems to capture and contain crude oil in the unlikely event of a future loss of control of a deepwater well in the Gulf of Mexico. In addition, the company is a member of the Subsea Well Response Project, which has the objective to further develop the industry's capability to contain and shut in subsea well control incidents in different regions of the world.
The company is committed to improving energy efficiency in its day-to-day operations and is required to comply with the greenhouse gas-related laws and regulations to which it is subject. Refer to Item 1A. Risk Factors on pages 18 through 21 for further discussion of greenhouse gas regulation and climate change and the associated risks to Chevron's business.
Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations on page 43 for additional information on environmental matters and their impact on Chevron, and on the company's 2018 environmental expenditures. Refer to page 43 and Note 23 beginning on page 86 for a discussion of environmental remediation provisions and year-end reserves.
Item 1A. Risk Factors
Chevron is a global energy company and its operating and financial results are subject to a variety of risks inherent in the global oil, gas, and petrochemical businesses. Many of these risks are not within the company's control and could materially impact the company's results of operations and financial condition.
Chevron is exposed to the effects of changing commodity prices Chevron is primarily in a commodities business that has a history of price volatility. The single largest variable that affects the company's results of operations is the price of crude oil, which can be influenced by general economic conditions, industry production and inventory levels, technology advancements, production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries (OPEC) or other producers, weather-related damage and disruptions, competing fuel prices, and geopolitical risks. Chevron evaluates the risk of changing commodity prices as a core part of its business planning process. An investment in the company carries significant exposure to fluctuations in global crude oil prices.
Extended periods of low prices for crude oil can have a material adverse impact on the company's results of operations, financial condition and liquidity. Among other things, the company's upstream earnings, cash flows, and capital and exploratory expenditure programs could be negatively affected, as could its production and proved reserves. Upstream assets may also become impaired. Downstream earnings could be negatively affected because they depend upon the supply and demand for refined products and the associated margins on refined product sales. A significant or sustained decline in liquidity could adversely affect the company's credit ratings, potentially increase financing costs and reduce access to capital markets. The company may be unable to realize anticipated cost savings, expenditure reductions and asset sales that are intended to compensate for such downturns. In some cases, liabilities

associated with divested assets may return to the company when an acquirer of those assets subsequently declares bankruptcy. In addition, extended periods of low commodity prices can have a material adverse impact on the results of operations, financial condition and liquidity of the company's suppliers, vendors, partners and equity affiliates upon which the company's own results of operations and financial condition depends.

The scope of Chevron's business will decline if the company does not successfully develop resources The company is in an extractive business; therefore, if it is not successful in replacing the crude oil and natural gas it produces with good prospects

for future organic opportunities or through acquisitions, the company’s business will decline. Creating and maintaining an inventory of projects depends on many factors, including obtaining and renewing rights to explore, develop and produce hydrocarbons; drilling success; reservoir optimization; ability to bring long-lead-time, capital-intensive projects to completion on budget and on schedule; and efficient and profitable operation of mature properties.

The company’s operations could be disrupted by natural or human causes beyond its control Chevron operates in both urban areas and remote and sometimes inhospitable regions. The company’s operations are therefore subject to disruption from natural or human causes beyond its control, including physical risks from hurricanes, severe storms, floods and other forms of severe weather, war, accidents, civil unrest, political events, fires, earthquakes, system failures, cyber threats and terrorist acts, any of which could result in suspension of operations or harm to people or the natural environment.

Chevron's risk management systems are designed to assess potential physical and other risks to its operations and assets and to plan for their resiliency. While capital investment reviews and decisions incorporate potential ranges of physical risks such as storm severity and frequency, sea level rise, air and water temperature, precipitation, fresh water access, wind speed, and earthquake severity, among other factors, it is difficult to predict with certainty the timing, frequency or severity of such events, any of which could have a material adverse effect on the company's results of operations or financial condition.

Cyberattacks targeting Chevron’s process control networks or other digital infrastructure could have a material adverse impact on the company’s business and results of operations There are numerous and evolving risks to Chevron's cybersecurity and privacy from cyber threat actors, including criminal hackers, state-sponsored intrusions, industrial espionage and employee malfeasance. These cyber threat actors, whether internal or external to Chevron, are becoming more sophisticated and coordinated in their attempts to access the company’s information technology (IT) systems and data, including the IT systems of cloud providers and other third parties with whom the company conducts business. Although Chevron devotes significant resources to prevent unwanted intrusions and to protect its systems and data, whether such data is housed internally or by external third parties, the company has experienced and will continue to experience cyber incidents of varying degrees in the conduct of its business. Cyber threat actors could compromise the company’s process control networks or other critical systems and infrastructure, resulting in disruptions to its business operations, injury to people, harm to the environment or its assets, disruptions in access to its financial reporting systems, or loss, misuse or corruption of its critical data and proprietary information, including without limitation its intellectual property and business information and that of its employees, customers, partners and other third parties. Any of the foregoing can be exacerbated by a delay or failure to detect a cyber incident. Further, the company has exposure to cyber incidents and the negative impacts of such incidents related to its critical data and proprietary information housed on third-party IT systems, including the cloud. The company has limited control and visibility over such third-party IT systems. Cyber events could result in significant financial losses, legal or regulatory violations, reputational harm, and legal liability and could ultimately have a material adverse effect on the company’s business and results of operations.

The company’s operations have inherent risks and hazards that require significant and continuous oversight Chevron’s results depend on its ability to identify and mitigate the risks and hazards inherent to operating in the crude oil and natural gas industry. The company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these risks effectively could impair our ability to operate and result in unexpected incidents, including releases, explosions or mechanical failures resulting in personal injury, loss of life, environmental damage, loss of revenues, legal liability and/or disruption to operations. Chevron has implemented and maintains a system of corporate policies, processes and systems, behaviors and compliance mechanisms to manage safety, health, environmental, reliability and efficiency risks; to verify compliance with applicable laws and policies; and to respond to and learn from unexpected incidents. In certain situations where Chevron is not the operator, the company may have limited influence and control over third parties, which may limit its ability to manage and control such risks.

Chevron’s business subjects the company to liability risks from litigation or government action The company produces, transports, refines and markets potentially hazardous materials, and it purchases, handles and disposes of other potentially hazardous materials in the course of its business. Chevron's operations also produce byproducts, which may be considered pollutants. Often these operations are conducted through joint ventures over which the company may have limited influence and control. Any of these activities could result in liability or significant delays in operations arising from private litigation or government action, either as a result of an accidental, unlawful discharge or as a result of new conclusions about the effects of the company’s operations on human health or the environment. In addition, to the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to the company’s causation of or contribution to the asserted damage, or to other mitigating factors.

For information concerning some of the litigation in which the company is involved, see Note 15 to the Consolidated Financial Statements, beginning on page 70.

The company does not insure against all potential losses, which could result in significant financial exposure The company does not have commercial insurance or third-party indemnities to fully cover all operational risks or potential liability in the event of a significant incident or series of incidents causing catastrophic loss. As a result, the company is, to a substantial extent, self-insured for such events. The company relies on existing liquidity, financial resources and borrowing capacity to meet short-term obligations that would arise from such an event or series of events. The occurrence of a significant incident or unforeseen liability for which the company is self-insured, not fully insured or for which insurance recovery is significantly delayed could have a material adverse effect on the company's results of operations or financial condition.

Political instability and significant changes in the legal and regulatory environment could harm Chevron's business The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates. As has occurred in the past, actions could be taken by governments to increase public ownership of the company's partially or wholly owned businesses or to impose additional taxes or royalties. In certain locations, governments have proposed or imposed restrictions on the company's operations, trade, currency exchange controls, burdensome taxes, and public disclosure requirements that might harm the company's competitiveness or relations with other governments or third parties. In other countries, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries, and internal unrest, acts of violence or strained relations between a government and the company or other governments may adversely affect the company's operations. Those developments have, at times, significantly affected the company's operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries. Further, Chevron is required to comply with U.S. sanctions and other trade laws and regulations which, depending upon their scope, could adversely impact the company's operations in certain countries. In addition, litigation or changes in national, state or local environmental regulations or laws, including those designed to stop or impede the development or production of oil and gas, such as those related to the use of hydraulic fracturing or bans on drilling, could adversely affect the company's current or anticipated future operations and profitability.

Regulation of greenhouse gas (GHG) emissions could increase Chevron's operational costs and reduce demand for Chevron's hydrocarbon and other products In the years ahead, companies in the energy industry, like Chevron, may be challenged by an increase in international and domestic regulation relating to GHG emissions. Like any significant changes in the regulatory environment, GHG regulation could have the impact of curtailing profitability in the oil and gas sector or rendering the extraction of the company's oil and gas resources economically infeasible. Although the IEA's World Energy Outlook scenarios anticipate oil and gas continuing to make up a significant portion of the global energy mix through 2040 and beyond given their respective advantages in transportation and power generation, if a new onset of regulation contributes to a decline in the demand for the company's products, this could have a material adverse effect on the company and its financial condition.

International agreements and national, regional and state legislation (e.g., California AB32, SB32 and AB398) and regulatory measures that aim to limit or reduce GHG emissions are currently in various stages of implementation. For example, the Paris Agreement went into effect in November 2016, and a number of countries are studying and may adopt additional policies to meet their Paris Agreement goals. In some jurisdictions, the company is already subject to currently implemented programs such as the U.S. Renewable Fuel Standard program, the European Union Emissions Trading System, and the California cap-and-trade program and related low carbon fuel standard obligations. Other jurisdictions are considering adopting or are in the process of implementing laws or regulations to directly regulate GHG emissions through similar or other mechanisms such as, for example, via a carbon tax (e.g., Singapore and Canada) or via a cap-and-trade program (e.g., Mexico and China). The landscape continues to be in a state of constant re-assessment and legal challenge with respect to these laws and regulations, making it difficult to predict with certainty the ultimate impact they will have on the company in the aggregate.

GHG emissions-related laws and related regulations and the effects of operating in a potentially carbon-constrained environment may result in increased and substantial capital, compliance, operating and maintenance costs and could, among other things, reduce demand for hydrocarbons and the company's hydrocarbon-based products, make the company's products more expensive, adversely affect the economic feasibility of the company's resources, and adversely affect the company's sales volumes, revenues and margins. GHG emissions (e.g., carbon dioxide and methane) that could be regulated include, among others, those associated with the company's exploration and production of hydrocarbons such as crude oil and natural gas; the upgrading of production from oil sands into synthetic oil; power generation; the conversion of crude oil and natural gas into refined hydrocarbon products; the processing, liquefaction and regasification of natural gas; the transportation of

crude oil, natural gas and related products and consumers' or customers' use of the company's hydrocarbon products. Many of these activities, such as consumers' and customers' use of the company's products, as well as actions taken by the company's competitors in response to such laws and regulations, are beyond the company's control. In addition, increasing attention to climate change risks has resulted in an increased possibility of governmental investigations and additional private litigation against the company.

Consideration of GHG issues and the responses to those issues through international agreements and national, regional or state legislation or regulations are integrated into the company's strategy and planning, capital investment reviews, and risk management tools and processes, where applicable. They are also factored into the company's long-range supply, demand and energy price forecasts. These forecasts reflect long-range effects from renewable fuel penetration, energy efficiency standards, climate-related policy actions, and demand response to oil and natural gas prices. Additionally, the company assesses carbon pricing risks by considering carbon costs in these forecasts. The actual level of expenditure required to comply with new or potential climate change-related laws and regulations and amount of additional investments in new or existing technology or facilities, such as carbon dioxide injection, is difficult to predict with certainty and is expected to vary depending on the actual laws and regulations enacted in a jurisdiction, the company's activities in it and market conditions.

The ultimate effect of international agreements and national, regional and state legislation and regulatory measures to limit GHG emissions on the company's financial performance, and the timing of these effects, will depend on a number of factors. Such factors include, among others, the sectors covered, the GHG emissions reductions required, the extent to which Chevron would be entitled to receive emission allowance allocations or would need to purchase compliance instruments on the open market or through auctions, the price and availability of emission allowances and credits, and the extent to which the company is able to recover the costs incurred through the pricing of the company's products in the competitive marketplace. Further, the ultimate impact of GHG emissions-related agreements, legislation and measures on the company's financial performance is highly uncertain because the company is unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Changes in management's estimates and assumptions may have a material impact on the company's consolidated financial statements and financial or operational performance in any given period In preparing the company's periodic reports under the Securities Exchange Act of 1934, including its financial statements, Chevron's management is required under applicable rules and regulations to make estimates and assumptions as of a specified date. These estimates and assumptions are based on management's best estimates and experience as of that date and are subject to substantial risk and uncertainty. Materially different results may occur as circumstances change and additional information becomes known. Areas requiring significant estimates and assumptions by management include impairments to property, plant and equipment; estimates of crude oil and natural gas recoverable reserves; accruals for estimated liabilities, including litigation reserves; and measurement of benefit obligations for pension and other postretirement benefit plans. Changes in estimates or assumptions or the information underlying the assumptions, such as changes in the company's business plans, general market conditions or changes in commodity prices, could affect reported amounts of assets, liabilities or expenses.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and character of the company's crude oil and natural gas properties and its refining, marketing, transportation and chemicals facilities are described beginning on page 3 under Item 1. Business. Information required by Subpart 1200 of Regulation S-K ("Disclosure by Registrants Engaged in Oil and Gas Producing Activities") is also contained in Item 1 and in Tables I through VII on pages 91 through 101. Note 17, "Properties, Plant and Equipment," to the company's financial statements is on page 77.

Item 3. Legal Proceedings

Governmental Proceedings The following is a description of legal proceedings that the company has determined to disclose for this reporting period that involve governmental authorities and certain monetary sanctions under federal, state and local laws that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment.
As previously disclosed, on August 6, 2012, a piping failure and fire occurred at the Chevron refinery in Richmond, California. The United States Environmental Protection Agency (EPA) issued alleged findings of violation related to the incident on

December 17, 2013, pursuant to its authority under the Clean Air Act Risk Management Plan program (RMP). Following the Richmond incident, EPA also conducted RMP inspections at Chevron's refineries in El Segundo, California; Pascagoula, Mississippi; Kapolei, Hawaii; and Salt Lake City, Utah. On October 24, 2018, the U.S. Department of Justice (DOJ) lodged with the United States District Court for the Northern District of California a consent decree executed by Chevron, DOJ, EPA, and the State of Mississippi that resolves all of EPA's alleged findings of violation related to the Richmond incident and subsequent RMP inspections. The consent decree includes the payment of a civil penalty of $2.95 million and the funding of supplemental environmental projects totaling $10 million. Chevron also agreed, as part of the consent decree, to investments in process safety enhancements at its current refineries, estimated at $150 million, a portion of which has already been spent. The consent decree is pending court approval.

Chevron facilities within the jurisdiction of California's Bay Area Air Quality Management District (BAAQMD) currently have multiple outstanding Notices of Violation (NOVs) issued by BAAQMD. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more. As previously disclosed, on June 26, 2018, Chevron received a proposal from the BAAQMD seeking to collectively resolve certain NOVs issued between 2015 and 2017 to Chevron's Richmond Refinery. On November 5, 2018, Chevron and the BAAQMD entered into a settlement agreement to resolve allegations in the disputed NOVs for a civil penalty of $222,000.

Chevron facilities within the jurisdiction of California's South Coast Air Quality Management District (SCAQMD) currently have multiple outstanding NOVs issued by SCAQMD. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more.

Other Proceedings Information related to other legal proceedings is included beginning on page 70 in Note 15 to the Consolidated Financial Statements.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

Information relating to the company's executive officers is included under "Executive Officers" in Part III, Item 10, "Directors, Executive Officers and Corporate Governance" on page 24, and is incorporated herein by reference.

PART II

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

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 11, 2019, stockholders of record numbered approximately 124,000. There are no restrictions on the company's ability to pay dividends. The information on Chevron's dividends are contained in the Quarterly Results tabulations on page 47.

Chevron Corporation Issuer Purchases of Equity Securities for Quarter Ended December 31, 2018

Period	Total Number of Shares Purchased [1,2]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares That May Yet be Purchased Under the Program[2]
Oct. 1 – Oct. 31, 2018	2,472,282	$118.35	2,472,126	—
Nov. 1 – Nov. 30, 2018	3,130,770	117.24	3,130,770	—
Dec. 1 – Dec. 31, 2018	3,046,000	$111.75	3,046,000	—
Total Oct. 1 – Dec. 31, 2018	8,649,052	$115.62	8,648,896	—

[1] Includes common shares repurchased from company employees and directors for personal income tax withholdings on the exercise of the stock options and shares delivered or attested to in satisfaction of the exercise price by holders of the employee and director stock options. The options were issued to and exercised by management under

Chevron long-term incentive plans.

[2] Refer to "Liquidity and Capital Resources" on page 38 for additional detail regarding the company's authorized stock repurchase program.

Item 6. Selected Financial Data

The selected financial data for years 2014 through 2018 are presented on page 90.

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

The index to Management's Discussion and Analysis of Financial Condition and Results of Operations, Consolidated Financial Statements and Supplementary Data is presented on page 27.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The company's discussion of interest rate, foreign currency and commodity price market risk is contained in Management's Discussion and Analysis of Financial Condition and Results of Operations — "Financial and Derivative Instrument Market Risk," beginning on page 41 and in Note 9 to the Consolidated Financial Statements, "Financial and Derivative Instruments," beginning on page 64.

Item 8. Financial Statements and Supplementary Data

The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page 27.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures The company's management has evaluated, with the participation of the Chief Executive Officer and the Chief Financial Officer, the effectiveness of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (Exchange Act)) as of the end of the period covered by this report. Based on this evaluation, management concluded that the company's disclosure controls and procedures were effective as of December 31, 2018.

(b) Management's Report on Internal Control Over Financial Reporting The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in the Exchange Act Rules 13a-15(f) and 15d-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company's internal control over financial reporting based on the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the company's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

(c) Changes in Internal Control Over Financial Reporting During the quarter ended December 31, 2018, there were no changes in the company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 22, 2019

Members of the Corporation's Executive Committee are the Executive Officers of the Corporation:

Name	Age	Current and Prior Positions (up to five years)	Primary Areas of Responsibility
M.K. Wirth	58	Chairman of the Board and Chief Executive Officer (since Feb 2018) Vice Chairman of the Board (Feb 2017 - Jan 2018) and Executive Vice President, Midstream and Development (Jan 2016 - Jan 2018) Executive Vice President, Downstream (Mar 2006 - Dec 2015)	Chairman of the Board and Chief Executive Officer
J.W. Johnson	59	Executive Vice President, Upstream (since Jun 2015) Senior Vice President, Upstream (Jan 2014 - Jun 2015)	Worldwide Exploration and Production Activities
P.R. Breber[1]	54	Executive Vice President, Downstream (since Jan 2016) Executive Vice President, Gas and Midstream (Apr 2015 - Dec 2015) Vice President, Gas and Midstream (Jan 2014 - Mar 2015)	Worldwide Manufacturing, Marketing and Lubricants; Chemicals
J.C. Geagea	59	Executive Vice President, Technology, Projects and Services (since Jun 2015) Senior Vice President, Technology, Projects and Services (Jan 2014 - Jun 2015)	Technology; Health, Environment and Safety; Project Resources Company; Procurement
M.A. Nelson[2]	55	Vice President, Midstream, Strategy and Policy (since Feb 2018) Vice President, Strategic Planning (Apr 2016 - Jan 2018) President, International Products (Jun 2010 - Mar 2016)	Corporate Strategy; Policy, Government and Public Affairs; Supply and Trading Activities; Shipping; Pipeline; Power and Energy Management
P.E. Yarrington[1]	62	Vice President and Chief Financial Officer (since Jan 2009)	Finance
R.H. Pate	56	Vice President and General Counsel (since Aug 2009)	Law, Governance and Compliance
R.J. Morris	53	Vice President and Chief Human Resources Officer (since Feb 2019)	Human Resources; Health and Medical; Diversity and Inclusion

Vice President, Human Resources (Oct 2016 - Jan 2019)
Vice President, Downstream Human Resources (Sep 2012 - Sep 2016)

[1] Effective April 1, 2019, Mr. Breber will assume the position of Vice President and Chief Financial Officer
[2] Effective March 1, 2019, Mr. Nelson will assume the position of Executive Vice President, Downstream

The information about directors required by Item 401(a), (d), (e) and (f) of Regulation S-K and contained under the heading “Election of Directors” in the Notice of the 2019 Annual Meeting of Stockholders and 2019 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), in connection with the company’s 2019 Annual Meeting (the “2019 Proxy Statement”), is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 405 of Regulation S-K and contained under the heading “Stock Ownership Information — Section 16(a) Beneficial Ownership Reporting Compliance” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 406 of Regulation S-K and contained under the heading “Corporate Governance — Business Conduct and Ethics Code” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(d)(4) and (5) of Regulation S-K and contained under the heading “Corporate Governance — Board Committees” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 11. Executive Compensation

The information required by Item 402 of Regulation S-K and contained under the headings “Executive Compensation,” “CEO Pay Ratio” and “Director Compensation” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(4) of Regulation S-K and contained under the heading “Corporate Governance — Board Committees” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(5) of Regulation S-K and contained under the heading “Corporate Governance — Management Compensation Committee Report” in the 2019 Proxy Statement is incorporated herein by reference into this Annual Report on Form 10-K. Pursuant to the rules and regulations of the SEC under the Exchange Act, the information under such caption incorporated by reference from the 2019 Proxy Statement shall not be deemed to be “soliciting material,” or to be “filed” with the Commission, or subject to Regulation 14A or 14C or the liabilities of Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by Item 403 of Regulation S-K and contained under the heading “Stock Ownership Information — Security Ownership of Certain Beneficial Owners and Management” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 201(d) of Regulation S-K and contained under the heading “Equity Compensation Plan Information” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by Item 404 of Regulation S-K and contained under the heading “Corporate Governance — Related Person Transactions” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(a) of Regulation S-K and contained under the heading “Corporate Governance — Director Independence” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services

The information required by Item 9(e) of Schedule 14A and contained under the heading “Board Proposal to Ratify PricewaterhouseCoopers LLP as the Independent Registered Public Accounting Firm for 2019” in the 2019 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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Management's Discussion and Analysis of Financial Condition and Results of Operations

Key Financial Results

Millions of dollars, except per-share amounts	2018	2017	2016
Net Income (Loss) Attributable to Chevron Corporation	$14,824	$9,195	$(497)
Per Share Amounts:			
Net Income (Loss) Attributable to Chevron Corporation			
– Basic	$7.81	$4.88	$(0.27)
– Diluted	$7.74	$4.85	$(0.27)
Dividends	$4.48	$4.32	$4.29
Sales and Other Operating Revenues	$158,902	$134,674	$110,215
Return on:			
Capital Employed	8.2 %	5.0 %	(0.1)%
Stockholders’ Equity	9.8 %	6.3 %	(0.3)%

Earnings by Major Operating Area

Millions of dollars	2018	2017	2016
Upstream			
United States	$3,278	$3,640	$(2,054)
International	10,038	4,510	(483)
Total Upstream	13,316	8,150	(2,537)
Downstream			
United States	2,103	2,938	1,307
International	1,695	2,276	2,128
Total Downstream	3,798	5,214	3,435
All Other	(2,290)	(4,169)	(1,395)
Net Income (Loss) Attributable to Chevron Corporation[1,2]	$14,824	$9,195	$(497)
[1] Includes foreign currency effects:	$611	$(446)	$58

[2] Income net of tax, also referred to as “earnings” in the discussions that follow.

Refer to the “Results of Operations” section beginning on page 32 for a discussion of financial results by major operating area for the three years ended December 31, 2018.

Business Environment and Outlook

Chevron is a global energy company with substantial business activities in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Canada, China, Colombia, Denmark, Indonesia, Kazakhstan, Myanmar, Nigeria, the Partitioned Zone between Saudi Arabia and Kuwait, the Philippines, Republic of Congo, Singapore, South Korea, Thailand, the United Kingdom, the United States, and Venezuela.

Earnings of the company depend mostly on the profitability of its upstream business segment. The most significant factor affecting the results of operations for the upstream segment is the price of crude oil, which is determined in global markets outside of the company’s control. In the company's downstream business, crude oil is the largest cost component of refined products. It is the company's objective to deliver competitive results and stockholder value in any business environment. Periods of sustained lower prices could result in the impairment or write-off of specific assets in future periods and cause the company to adjust operating expenses and capital and exploratory expenditures, along with other measures intended to improve financial performance.

The effective tax rate for the company can change substantially during periods of significant earnings volatility. This is due to the mix effects that are impacted both by the absolute level of earnings or losses and whether they arise in higher or lower tax rate jurisdictions. As a result, a decline or increase in the effective income tax rate in one period may not be indicative of expected results in future periods. Note 16 provides the company’s effective income tax rate for the last three years.

Refer to the "Cautionary Statement Relevant to Forward-Looking Information" on page 2 and to "Risk Factors" in Part I, Item 1A, on pages 18 through 21 for a discussion of some of the inherent risks that could materially impact the company's results of operations or financial condition.

The company continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company's financial performance and value growth. Asset dispositions and restructurings may result in significant gains or losses in future periods. The company's asset sale program for 2018 through 2020 is targeting before-tax proceeds of $5-10 billion. Proceeds related to asset sales were $2.0 billion in 2018.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of movements in prices for crude oil and natural gas. Management takes these developments into account in the conduct of daily operations and for business planning.
Comments related to earnings trends for the company's major business areas are as follows:
Upstream Earnings for the upstream segment are closely aligned with industry prices for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry production and inventory levels, technology advancements, production quotas or other actions imposed by the Organization of Petroleum Exporting Countries (OPEC) or other producers, actions of regulators, weather-related damage and disruptions, competing fuel prices, and regional supply interruptions or fears thereof that may be caused by military conflicts, civil unrest or political uncertainty. Any of these factors could also inhibit the company's production capacity in an affected region. The company closely monitors developments in the countries in which it operates and holds investments, and seeks to manage risks in operating its facilities and businesses. The longer-term trend in earnings for the upstream segment is also a function of other factors, including the company's ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms of contracts, and changes in tax and other applicable laws and regulations.
The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. However, price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can be subject to external factors beyond the company's control including, among other things, the general level of inflation, tariffs or other taxes imposed on goods or services, commodity prices and prices charged by the industry's material and service providers, which can be affected by the volatility of the industry's own supply-and-demand conditions for such materials and services. Modest cost pressures continue in rig-related services across North America unconventional markets. Cost pressures have softened in well completion activity particularly in the Permian Basin, but are expected to rise when pipeline takeaway constraints are resolved in late 2019. International and offshore markets are showing indications of increased activity levels with limited cost pressures to date.
Capital and exploratory expenditures and operating expenses could also be affected by damage to production facilities caused by severe weather or civil unrest, delays in construction, or other factors.
The chart above shows the trend in benchmark prices for Brent crude oil, West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. The majority of the company's equity crude production is priced based on the Brent benchmark. The Brent price averaged $71 per barrel for the full-year 2018, compared to $54 in 2017. Crude oil prices increased throughout the first three quarters of 2018 due to solid demand combined with OPEC production cuts. Late in the year, continued U.S. shale growth, combined with unexpected short-term waivers from Iranian sanctions granted to several countries, led to excess supply conditions, resulting in a decrease in oil prices. In response, OPEC agreed to new production cuts in early December. As of mid-February 2019, the Brent price was $64 per barrel.
The WTI price averaged $65 per barrel for the full-year 2018, compared to $51 in 2017. WTI traded at a discount to Brent throughout 2018. Differentials to Brent have ranged between $3 to $10 in 2018 primarily due to pipeline infrastructure constraints which have restricted flows on the inland crude to export outlets on the Gulf Coast, in addition to variability in

other factors impacting supply and demand of each benchmark crude. As of mid-February 2019, the WTI price was $54 per barrel.
Chevron has interests in the production of heavy crude oil in California, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page 37 for the company’s average U.S. and international crude oil sales prices.)
In contrast to price movements in the global market for crude oil, price changes for natural gas are more closely aligned with supply-and-demand conditions in regional markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged $3.12 per thousand cubic feet (MCF) during 2018, compared with $2.97 during 2017. As of mid-February 2019, the Henry Hub spot price was $2.61 per MCF.
Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. Chevron sells natural gas into the domestic pipeline market in many locations. In some locations, Chevron has invested in long-term projects to produce and liquefy natural gas for transport by tanker to other markets. The company's long-term contract prices for liquefied natural gas (LNG) are typically linked to crude oil prices. Most of the equity LNG offtake from the operated Australian LNG projects is committed under binding long-term contracts, with the remainder to be sold in the Asian spot LNG market. The Asian spot market reflects the supply and demand for LNG in the Pacific Basin and is not directly linked to crude oil prices. International natural gas realizations averaged $6.29 per MCF during 2018, compared with $4.62 per MCF during 2017. (See page 37 for the company’s average natural gas realizations for the U.S. and international regions.)
The company’s worldwide net oil-equivalent production in 2018 averaged 2.930 million barrels per day. About one-sixth of the company’s net oil-equivalent production in 2018 occurred in the OPEC-member countries of Angola, Nigeria, Republic of Congo and Venezuela. OPEC quotas had no effect on the company’s net crude oil production in 2018 or 2017.
The company estimates that net oil-equivalent production in 2019 will grow 4 to 7 percent compared to 2018, assuming a Brent crude oil price of $60 per barrel and excluding the impact of anticipated 2019 asset sales. This estimate is subject to many factors and uncertainties, including quotas or other actions that may be imposed by OPEC; price effects on entitlement volumes; changes in fiscal terms or restrictions on the scope of company operations; delays in construction; reservoir performance; greater-than-expected declines in production from mature fields; start-up or ramp-up of projects; fluctuations in demand for natural gas in various markets; weather conditions that may shut in production; civil unrest; changing geopolitics; delays in completion of maintenance turnarounds; or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and the time lag between initial exploration and the beginning of production. The company has increased its investment emphasis on short-cycle projects.

Management's Discussion and Analysis of Financial Condition and Results of Operations

In the Partitioned Zone between Saudi Arabia and Kuwait, production was shut-in beginning in May 2015 as a result of difficulties in securing work and equipment permits. Net oil-equivalent production in the Partitioned Zone in 2014 was 81,000 barrels per day. During 2015, net oil-equivalent production averaged 28,000 barrels per day. As of early 2019, production remains shut in and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait. The financial effects from the loss of production in 2018 were not significant and are not expected to be significant in 2019.

Chevron has interests in Venezuelan crude oil production assets operated by independent equity affiliates. During 2018, net oil equivalent production in Venezuela averaged 44,000 barrels per day. The operating environment in Venezuela has been deteriorating for some time. In January 2019, the United States government issued sanctions against the Venezuelan national oil company, Petroleos de Venezuela, S.A. (PdVSA), which is the company's partner in the equity affiliates. The equity affiliates continue to operate, and the company is conducting its business pursuant to general licenses issued coincident with the new sanctions. Future events could result in the environment in Venezuela becoming more challenged, which could lead to increased business disruption and volatility in the associated financial results.

Net proved reserves for consolidated companies and affiliated companies totaled 12.1 billion barrels of oil-equivalent at year-end 2018, an increase of 3 percent from year-end 2017. The reserve replacement ratio in 2018 was 136 percent. Refer to Table V beginning on page 95 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2016 and each year-end from 2016 through 2018, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2018.

Refer to the "Results of Operations" section on pages 32 through 34 for additional discussion of the company's upstream business.

Downstream Earnings for the downstream segment are closely tied to margins on the refining, manufacturing and marketing of products that include gasoline, diesel, jet fuel, lubricants, fuel oil, fuel and lubricant additives, and petrochemicals. Industry margins are sometimes volatile and can be affected by the global and regional supply-and-demand balance for refined products and petrochemicals, and by changes in the price of crude oil, other refinery and petrochemical feedstocks, and natural gas. Industry margins can also be influenced by inventory levels, geopolitical events, costs of materials and services, refinery or chemical plant capacity utilization, maintenance programs, and disruptions at refineries or chemical plants resulting from unplanned outages due to severe weather, fires or other operational events.

Other factors affecting profitability for downstream operations include the reliability and efficiency of the company's refining, marketing and petrochemical assets, the effectiveness of its crude oil and product supply functions, and the volatility of tanker-charter rates for the company's shipping operations, which are driven by the industry's demand for crude oil and product tankers. Other factors beyond the company's control include the general level of inflation and energy costs to operate the company's refining, marketing and petrochemical assets and changes in tax laws and regulations.

The company's most significant marketing areas are the West Coast and Gulf Coast of the United States and Asia. Chevron operates or has significant ownership interests in refineries in each of these areas.

Refer to the "Results of Operations" section on pages 32 through 34 for additional discussion of the company's downstream operations.

All Other consists of worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities and technology companies.

Operating Developments

Key operating developments and other events during 2018 and early 2019 included the following:

Upstream

Australia Achieved start-up of Train 2 at the Wheatstone LNG Project.

United States Produced first oil from the Big Foot Project in the deepwater Gulf of Mexico.

Downstream

South Africa and Botswana Completed the sale of refining, marketing and lubricant assets.
United States Chevron Phillips Chemical Company LLC (CPChem), the company's 50 percent-owned affiliate, commenced operations of a new ethane cracker at its Cedar Bayou facility in Baytown, Texas.

Management's Discussion and Analysis of Financial Condition and Results of Operations

United States In January 2019, Chevron announced it has signed an agreement to acquire a 110,000 barrels per day refinery located in Pasadena, Texas. The transaction is expected to close later in the first-half of 2019, subject to regulatory approvals.

Other

Common Stock Dividends The 2018 annual dividend was $4.48 per share, making 2018 the 31st consecutive year that the company increased its annual per share dividend payout. In January 2019, the company's Board of Directors approved a $0.07 per share increase in the quarterly dividend to $1.19 per share, payable in March 2019, representing an increase of 6 percent.

Common Stock Repurchase Program The company purchased $1.75 billion of its common stock in 2018 under its stock repurchase program.

Results of Operations

The following section presents the results of operations and variances on an after-tax basis for the company's business segments – Upstream and Downstream – as well as for "All Other." Earnings are also presented for the U.S. and international geographic areas of the Upstream and Downstream business segments. Refer to Note 13, beginning on page 66, for a discussion of the company's "reportable segments." This section should also be read in conjunction with the discussion in "Business Environment and Outlook" on pages 28 through 31.

U.S. Upstream

Millions of dollars	2018	2017	2016
Earnings	$3,278	$3,640	$(2,054)

U.S. upstream earnings were $3.28 billion in 2018, compared with $3.64 billion in 2017. The decrease in earnings was primarily due to the absence of the 2017 benefit from U.S. tax reform of $3.33 billion, higher other tax items of $160 million and higher exploration expense of $350 million, partially offset by higher crude oil realizations of $2.45 billion and higher crude oil production of $1.12 billion.

U.S. upstream earnings were $3.64 billion in 2017, compared with a loss of $2.05 billion from 2016. The improvement in earnings reflected a benefit of $3.33 billion from U.S. tax reform, higher crude oil and natural gas realizations of $1.3 billion and lower depreciation expenses of $650 million, primarily reflecting a decrease in impairments and other asset write-offs. Lower operating expenses of $140 million also contributed to the improvement.

The company's average realization for U.S. crude oil and natural gas liquids in 2018 was $58.17 per barrel, compared with $44.53 in 2017 and $35.00 in 2016. The average natural gas realization was $1.86 per thousand cubic feet in 2018, compared with $2.10 in 2017 and $1.59 in 2016.

Net oil-equivalent production in 2018 averaged 791,000 barrels per day, up 16 percent from 2017 and up 14 percent from 2016. Between 2018 and 2017, production increases from shale and tight properties in the Permian Basin in Texas and New

Management's Discussion and Analysis of Financial Condition and Results of Operations

Mexico and base business in the Gulf of Mexico were partially offset by the effect of asset sales of 35,000 barrels per day. Between 2017 and 2016, production increases from shale and tight properties in the Permian Basin in Texas and New Mexico and base business in the Gulf of Mexico were more than offset by the effect of asset sales of 59,000 barrels per day and normal field declines.

The net liquids component of oil-equivalent production for 2018 averaged 618,000 barrels per day, up 19 percent from 2017 and up 23 percent from 2016. Net natural gas production averaged 1.03 billion cubic feet per day in 2018, up 7 percent from 2017 and down 8 percent from 2016. Refer to the “Selected Operating Data” table on page 37 for a three-year comparison of production volumes in the United States.

International Upstream

Millions of dollars	2018	2017	2016
Earnings*	$10,038	$4,510	$(483)
*Includes foreign currency effects:	$545	$(456)	$122

International upstream earnings were $10.04 billion in 2018, compared with $4.51 billion in 2017. The increase in earnings was primarily due to higher crude oil and natural gas realizations of $3.38 billion and $1.38 billion, respectively, higher natural gas sales volumes of $1.67 billion, partially offset by lower gains on asset sales of $640 million, higher depreciation, operating and tax expenses of $470 million, $460 million and $230 million, respectively. Foreign currency effects had a favorable impact on earnings of $1.00 billion between periods.

International upstream earnings were $4.51 billion in 2017, compared with a loss of $483 million in 2016. The increase in earnings was primarily due to higher crude oil realizations of $2.59 billion, higher natural gas sales volumes of $1.22 billion, higher gains on asset sales of $750 million, and lower operating expenses of $410 million. Foreign currency effects had an unfavorable impact on earnings of $578 million between periods.

The company’s average realization for international crude oil and natural gas liquids in 2018 was $64.25 per barrel, compared with $49.46 in 2017 and $38.61 in 2016. The average natural gas realization was $6.29 per thousand cubic feet in 2018, compared with $4.62 and $4.02 in 2017 and 2016, respectively.

International net oil-equivalent production was 2.14 million barrels per day in 2018, up 4 percent from 2017 and up 12 percent from 2016. Between 2018 and 2017, production increases from major capital projects, primarily Wheatstone and Gorgon in Australia, were partially offset by normal field declines, production entitlement effects and the impact of asset sales of 14,000 barrels per day. Between 2017 and 2016, production increases from major capital projects and lower planned maintenance-related downtime were partially offset by production entitlement effects in several locations and normal field declines.

The net liquids component of international oil-equivalent production was 1.16 million barrels per day in 2018, down 3 percent from 2017 and down 4 percent from 2016. International net natural gas production of 5.86 billion cubic feet per day in 2018 was up 16 percent from 2017 and up 42 percent from 2016.

Refer to the “Selected Operating Data” table, on page 37, for a three-year comparison of international production volumes.

U.S. Downstream

Millions of dollars	2018	2017	2016
Earnings	$2,103	$2,938	$1,307

U.S. downstream operations earned $2.10 billion in 2018, compared with $2.94 billion in 2017. The decrease was mainly due to the absence of the 2017 benefit from U.S. tax reform of $1.16 billion and higher operating expenses of $420 million, primarily due to planned refinery turnaround activity. Partially offsetting these were higher margins on refined product sales of $380 million and higher equity earnings from the 50 percent-owned CPChem of $320 million, primarily reflecting the absence of impacts from Hurricane Harvey.

U.S. downstream operations earned $2.94 billion in 2017, compared with $1.31 billion in 2016. The increase was primarily due to a $1.16 billion benefit from U.S. tax reform, higher margins on refined product sales of $380 million, lower operating expenses of $160 million, and the absence of an asset impairment of $110 million. Partially offsetting this increase were lower gains on asset sales of $90 million and lower earnings from the 50 percent-owned CPChem of $70 million, primarily reflecting the impacts from Hurricane Harvey.

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Management's Discussion and Analysis of Financial Condition and Results of Operations

Total refined product sales of 1.22 million barrels per day in 2018 were up 2 percent from 2017. Sales were 1.20 million barrels per day in 2017, a decrease of 1 percent from 2016, primarily due to the divestment of Hawaii refining and marketing assets in fourth quarter 2016.
Refer to the “Selected Operating Data” table on page 37 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.
International Downstream

Millions of dollars	2018	2017	2016
Earnings*	$1,695	$2,276	$2,128
*Includes foreign currency effects:	$71	$(90)	$(25)

International downstream earned $1.70 billion in 2018, compared with $2.28 billion in 2017. The decrease in earnings was largely due to lower margins on refined product sales of $590 million and lower gains on asset sales of $470 million, partially offset by lower operating expenses of $290 million. The sale of the company's Canadian refining and marketing business in third quarter 2017 and the sale of the southern Africa refining and marketing business in third quarter 2018 primarily contributed to the lower margins and operating expenses. Foreign currency effects had a favorable impact on earnings of $161 million between periods.
International downstream earned $2.28 billion in 2017, compared with $2.13 billion in 2016. The increase in earnings was primarily due to higher gains on asset sales of $360 million, partially offset by higher operating expenses of $140 million. Foreign currency effects had an unfavorable impact on earnings of $65 million between periods.
Total refined product sales of 1.44 million barrels per day in 2018 were down 4 percent from 2017, primarily due to the sales of the company's Canadian refining and marketing assets in third quarter 2017 and southern Africa refining and marketing business in third quarter 2018. Sales of 1.49 million barrels per day in 2017 were up 2 percent from 2016, primarily due to higher diesel and jet fuel sales.
Refer to the “Selected Operating Data” table on page 37, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.
All Other

Millions of dollars	2018	2017	2016
Net charges*	$(2,290)	$(4,169)	$(1,395)
*Includes foreign currency effects:	$(5)	$100	$(39)

All Other consists of worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.
Net charges in 2018 decreased $1.88 billion from 2017. The change between periods was mainly due to absence of a prior year tax charge of $2.47 billion related to U.S. tax reform, lower employee expenses and the absence of a reclamation related charge for a former mining asset, partially offset by other unfavorable tax items and higher interest expense. Foreign currency effects increased net charges by $105 million between periods. Net charges in 2017 increased $2.77 billion from 2016, mainly due to higher tax items, primarily reflecting a $2.47 billion expense from U.S. tax reform, higher interest expense and a reclamation related charge for a former mining asset, partially offset by lower employee expense. Foreign currency effects decreased net charges by $139 million between periods.
Consolidated Statement of Income
Comparative amounts for certain income statement categories are shown below:

Millions of dollars	2018	2017	2016
Sales and other operating revenues	$158,902	$134,674	$110,215

Sales and other operating revenues increased in 2018 mainly due to higher crude oil, refined product and natural gas prices. The increase between 2017 and 2016 was primarily due to higher refined product and crude oil prices, higher crude oil volumes, and higher natural gas volumes.
Beginning in 2018, excise, value-added and similar taxes collected on behalf of third parties were no longer included in "Sales and other operating revenue", but were netted in "Taxes other than on income" in accordance with ASU 2014-09. 2017 and 2016 include $7.19 billion and $6.91 billion, respectively, in taxes collected on behalf of third parties.

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Millions of dollars	2018	2017	2016
Income from equity affiliates	$6,327	$4,438	$2,661

Income from equity affiliates increased in 2018 from 2017 mainly due to higher upstream-related earnings from Tengizchevroil in Kazakhstan, Petroboscan and Petropiar in Venezuela, and higher downstream-related earnings from CPChem.

Income from equity affiliates increased in 2017 from 2016 mainly due to higher upstream-related earnings from Tengizchevroil in Kazakhstan and Angola LNG.

Refer to Note 14, beginning on page 69, for a discussion of Chevron's investments in affiliated companies.

Millions of dollars	2018	2017	2016
Other income	$1,110	$2,610	$1,596

Other income of $1.1 billion in 2018 included net gains from asset sales of $713 million before-tax. Other income in 2017 and 2016 included net gains from asset sales of $2.2 billion and $1.1 billion before-tax, respectively. Interest income was approximately $192 million in 2018, $107 million in 2017 and $145 million in 2016. Foreign currency effects decreased other income by $123 million in 2018, $131 million in 2017, and $186 million in 2016.

Millions of dollars	2018	2017	2016
Purchased crude oil and products	$94,578	$75,765	$59,321

Crude oil and product purchases increased $18.8 billion in 2018, primarily due to higher crude oil and refined product prices, partially offset by lower crude oil volumes. Purchases increased $16.4 billion in 2017, primarily due to higher crude oil and refined product prices, and higher refined product and crude oil volumes.

Millions of dollars	2018	2017	2016
Operating, selling, general and administrative expenses	$24,382	$23,237	$24,207

Operating, selling, general and administrative expenses increased $1.1 billion between 2018 and 2017. The increase included higher services and fees of $450 million, a receivable write-down for $270 million, higher transportation expenses of $200 million, and a contractual settlement for $180 million.

Operating, selling, general and administrative expenses decreased $1.0 billion between 2017 and 2016. The decrease included lower employee expenses of $690 million and non-operated joint venture expenses of $380 million.

Millions of dollars	2018	2017	2016
Exploration expense	$1,210	$864	$1,033

Exploration expenses in 2018 increased from 2017 primarily due to higher charges for well write-offs, partially offset by lower geological and geophysical expenses. Exploration expenses in 2017 decreased from 2016 primarily due to lower charges for well write-offs.

Millions of dollars	2018	2017	2016
Depreciation, depletion and amortization	$19,419	$19,349	$19,457

Depreciation, depletion and amortization expenses increased in 2018 from 2017 mainly due to higher production levels for certain oil and gas producing fields, partially offset by lower depreciation rates for certain oil and gas producing fields, and lower impairment charges.

The decrease in 2017 from 2016 was primarily due to lower impairments and lower depreciation rates for certain oil and gas producing properties, and the absence of a 2016 impairment of a downstream asset. Partially offsetting the decrease were higher production levels, accretion and write-offs for certain oil and gas producing fields, and a reclamation related charge for a former mining asset.

Millions of dollars	2018	2017	2016
Taxes other than on income	$4,867	$12,331	$11,668

Beginning in 2018, excise, value-added and similar taxes collected on behalf of third parties were netted in "Taxes other than on income" and were no longer included in "Sales and other operating revenues," in accordance with ASU 2014-09. 2017 and 2016 include $7.19 billion and $6.91 billion, respectively, in taxes collected on behalf of third parties. The further decrease in 2018 from 2017 was mainly due to lower local and municipal taxes and licenses, partially offset by higher duties reflecting

increased production. Taxes other than on income increased in 2017 from 2016 primarily due to higher duties, higher crude oil, refined product and natural gas sales, and higher production.

Millions of dollars	2018	2017	2016
Interest and debt expense	$748	$307	$201

Interest and debt expenses increased in 2018 from 2017 mainly due to a decrease in the amount of interest capitalized. Interest and debt expenses increased in 2017 from 2016 due to higher interest costs on long-term debt, partially offset by an increase in the amount of interest capitalized.

Millions of dollars	2018	2017	2016
Other components of net periodic benefit costs	$560	$648	$745

Other components of net periodic benefit costs decreased in 2018 from 2017 primarily due to a higher asset base for expected returns and a decrease in recognized actuarial losses arising during the period. The decrease in 2017 from 2016 was mainly due to lower interest costs, lower settlement costs, and a decrease in amortization of prior service costs, partially offset by an increase in plan asset values. This line was added to the Consolidated Statement of Income in accordance with the adoption of ASU 2017-07.

Millions of dollars	2018	2017	2016
Income tax expense (benefit)	$5,715	$(48)	$(1,729)

The increase in income tax expense in 2018 of $5.76 billion is due to the increase in total income before tax for the company of $11.35 billion and the absence of the remeasurement benefits from U.S. tax reform recognized in 2017. U.S. income before tax increased from a loss of $441 million in 2017 to a profit of $4.73 billion in 2018. This increase in earnings before tax was primarily driven by the effect of higher crude oil prices. The U.S. tax charge increased by $3.69 billion between year-over-year periods from a $2.97 billion benefit in 2017 to a $724 million charge in 2018. 2017 included a $2.02 billion benefit from U.S. tax reform, which primarily reflected the remeasurement of U.S. deferred tax assets and liabilities.

International income before tax increased from $9.66 billion in 2017 to $15.84 billion in 2018. This $6.18 billion increase was primarily driven by the effect of higher crude oil prices. The higher crude prices primarily drove the $2.06 billion increase in international income tax expense between year-over-year periods, from $2.93 billion in 2017 to $4.99 billion in 2018.

The decline in income tax benefit in 2017 of $1.68 billion is due to the increase in total income before tax for the company of $11.38 billion and the remeasurement impacts of U.S. tax reform. U.S. losses before tax decreased from a loss of $4.32 billion in 2016 to a loss of $441 million in 2017. This decrease in losses before tax was primarily driven by the effect of higher crude oil prices. The U.S. tax benefit increased by $650 million between year-over-year periods from $2.32 billion in 2016 to $2.97 billion in 2017. The U.S. tax benefit for 2017 included a $2.02 billion benefit from U.S. tax reform, which primarily reflected the remeasurement of U.S. deferred tax assets and liabilities, and a reduction of $1.37 billion as result of the impact of a decrease in losses before tax of $3.88 billion.

International income before tax increased from $2.16 billion in 2016 to $9.66 billion in 2017. This $7.50 billion increase was primarily driven by the effect of higher crude oil prices and gains on asset sales primarily in Indonesia and Canada. The higher crude prices primarily drove the $2.34 billion increase in international income tax expense between year-over-year periods, from $588 million in 2016 to $2.93 billion in 2017.

Refer also to the discussion of the effective income tax rate in Note 16 on page 74.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Selected Operating Data[1,2]

	2018	2017	2016
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	618	519	504
Net Natural Gas Production (MMCFPD)[3]	1,034	970	1,120
Net Oil-Equivalent Production (MBOEPD)	791	681	691
Sales of Natural Gas (MMCFPD)	3,481	3,331	3,317
Sales of Natural Gas Liquids (MBPD)	110	30	30
Revenues from Net Production			
Liquids ($/Bbl)	$58.17	$44.53	$35.00
Natural Gas ($/MCF)	$1.86	$2.10	$1.59
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)[4]	1,164	1,204	1,215
Net Natural Gas Production (MMCFPD)[3]	5,855	5,062	4,132
Net Oil-Equivalent Production (MBOEPD)[4]	2,139	2,047	1,903
Sales of Natural Gas (MMCFPD)	5,604	5,081	4,491
Sales of Natural Gas Liquids (MBPD)	34	29	24
Revenues from Liftings			
Liquids ($/Bbl)	$64.25	$49.46	$38.61
Natural Gas ($/MCF)	$6.29	$4.62	$4.02
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD)[4]			
United States	791	681	691
International	2,139	2,047	1,903
Total	2,930	2,728	2,594
U.S. Downstream			
Gasoline Sales (MBPD)[5]	627	625	631
Other Refined Product Sales (MBPD)	591	572	582
Total Refined Product Sales (MBPD)	1,218	1,197	1,213
Sales of Natural Gas Liquids (MBPD)	74	109	115
Refinery Input (MBPD)[6]	905	901	900
International Downstream			
Gasoline Sales (MBPD)[5]	336	365	382
Other Refined Product Sales (MBPD)	1,101	1,128	1,080
Total Refined Product Sales (MBPD)[7]	1,437	1,493	1,462
Sales of Natural Gas Liquids (MBPD)	62	64	61
Refinery Input (MBPD)[8]	706	760	788

[1] Includes company share of equity affiliates.

[2] MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day; MBOEPD – thousands of barrels of oil-equivalents per day; Bbl – barrel; MCF – thousands of cubic feet. Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of crude oil.

[3] Includes natural gas consumed in operations (MMCFPD):			
United States	35	37	54
International	584	528	432
[4] Includes net production of synthetic oil:			
Canada	53	51	50
Venezuela affiliate	24	28	28

[5] Includes branded and unbranded gasoline.
[6] In November 2016, the company sold its interests in the Hawaii Refinery, which included operable capacity of 54,000 barrels per day.
[7] Includes sales of affiliates (MBPD): 373 366 377
[8] In September 2018, the company sold its interest in the Cape Town Refinery in Cape Town, South Africa, which had an operable capacity of 110,000 barrels per day. In September 2017, the company sold the Burnaby Refinery in British Columbia, Canada, which had operable capacity of 55,000 barrels per day.

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Liquidity and Capital Resources
Sources and uses of cash
The strength of the company's balance sheet enabled it to fund any timing differences throughout the year between cash inflows and outflows.
Cash, Cash Equivalents, Marketable Securities and Time Deposits Total balances were $10.3 billion and $4.8 billion at December 31, 2018 and 2017, respectively. Cash provided by operating activities in 2018 was $30.6 billion, compared with $20.3 billion in 2017 and $12.7 billion in 2016, reflecting higher crude oil prices and increased production. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.0 billion in 2018, $1.0 billion in 2017 and $0.9 billion in 2016. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.0 billion in 2018, $4.9 billion in 2017 and $3.2 billion in 2016.
Restricted cash of $1.1 billion and $1.1 billion at December 31, 2018 and 2017, respectively, was held in cash and short-term marketable securities and recorded as "Deferred charges and other assets" and "Prepaid expenses and other current assets" on the Consolidated Balance Sheet. These amounts are generally associated with upstream abandonment activities, tax payments, funds held in escrow for tax-deferred exchanges and refundable deposits related to pending asset sales.
Dividends Dividends paid to common stockholders were $8.5 billion in 2018, $8.1 billion in 2017 and $8.0 billion in 2016.
Debt and Capital Lease Obligations Total debt and capital lease obligations were $34.5 billion at December 31, 2018, down from $38.8 billion at year-end 2017.
The $4.3 billion decrease in total debt and capital lease obligations during 2018 was primarily due to the repayment of long-term notes totaling $6.7 billion as they matured during 2018, partly offset by an increase in commercial paper.
The company's debt and capital lease obligations due within one year, consisting primarily of commercial paper, redeemable long-term obligations and the current portion of long-term debt, totaled $15.6 billion at December 31, 2018, compared with $15.2 billion at year-end 2017. Of these amounts, $9.9 billion and $10.0 billion were reclassified to long-term debt at the end of 2018 and 2017, respectively.
At year-end 2018, settlement of these obligations was not expected to require the use of working capital in 2019, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.
Chevron has an automatic shelf registration statement that expires in May 2021 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

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The major debt rating agencies routinely evaluate the company’s debt, and the company’s cost of borrowing can increase or decrease depending on these debt ratings. The company has outstanding public bonds issued by Chevron Corporation and Texaco Capital Inc. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard and Poor’s Corporation and Aa2 by Moody’s Investors Service. The company’s U.S. commercial paper is rated A-1+ by Standard and Poor’s and P-1 by Moody’s. All of these ratings denote high-quality, investment-grade securities.

The company’s future debt level is dependent primarily on results of operations, cash that may be generated from asset dispositions, the capital program and shareholder distributions. Based on its high-quality debt ratings, the company believes that it has substantial borrowing capacity to meet unanticipated cash requirements. During extended periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, the company can also modify capital spending plans and discontinue or curtail the stock repurchase program to provide flexibility to continue paying the common stock dividend and also remain committed to retaining the company’s high-quality debt ratings.

Committed Credit Facilities Information related to committed credit facilities is included in Note 18, Short-Term Debt, on page 77.

Common Stock Repurchase Program In July 2010, the Board of Directors approved an ongoing stock repurchase program with no set term or monetary limits. From the inception of the program through the end of 2018, the company purchased 195.8 million shares for $21.75 billion, including 14.9 million shares for $1.75 billion in the second half 2018. On February 1, 2019, the company announced that the Board of Directors authorized a new stock repurchase program with a maximum dollar limit of $25 billion and no set term limits. Repurchases may be made from time to time in the open market, by block purchases, in privately negotiated transactions or in such other manner as determined by the company. The timing of the repurchases and the actual amount repurchased will depend on a variety of factors, including the market price of the company's shares, general market and economic conditions, and other factors. The stock repurchase program does not obligate the company to acquire any particular amount of common stock, and it may be suspended or discontinued at any time.

Capital and Exploratory Expenditures

Capital and exploratory expenditures by business segment for 2018, 2017 and 2016 are as follows:

	2018			2017			2016		
Millions of dollars	U.S.	Int’l.	Total	U.S.	Int’l.	Total	U.S.	Int’l.	Total
Upstream	$7,128	$10,529	$17,657	$5,145	$11,243	$16,388	$4,713	$15,403	$20,116
Downstream	1,582	611	2,193	1,656	534	2,190	1,545	527	2,072
All Other	243	13	256	239	4	243	235	5	240
Total	$8,953	$11,153	$20,106	$7,040	$11,781	$18,821	$6,493	$15,935	$22,428
Total, Excluding Equity in Affiliates	$8,651	$5,739	$14,390	$6,295	$7,783	$14,078	$5,456	$13,202	$18,658

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Total expenditures for 2018 were $20.1 billion, including $5.7 billion for the company’s share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2017 and 2016, expenditures were $18.8 billion and $22.4 billion, respectively, including the company’s share of affiliates’ expenditures of $4.7 billion and $3.8 billion, respectively.

Of the $20.1 billion of expenditures in 2018, 88 percent, or $17.7 billion, related to upstream activities. Approximately 87 percent was expended for upstream operations in 2017 and 90 percent in 2016. International upstream accounted for 60 percent of the worldwide upstream investment in 2018, 69 percent in 2017 and 77 percent in 2016.

The company estimates that 2019 capital and exploratory expenditures will be $20 billion, including $6.3 billion of spending by affiliates. This is in line with 2018 expenditures, and reflects a robust portfolio of upstream and downstream investments, highlighted by the company's Permian Basin position, and additional shale and tight development in other basins. Approximately 87 percent of the total, or $17.3 billion, is budgeted for exploration and production activities. Approximately $10.4 billion of planned upstream capital spending relates to base producing assets, including $3.6 billion for the Permian and $1.6 billion for other shale and tight rock investments. Approximately $5.1 billion of the upstream program is planned for major capital projects underway, including $4.3 billion associated with the Future Growth and Wellhead Pressure Management Project at the Tengiz field in Kazakhstan. Global exploration funding is expected to be about $1.3 billion. Remaining upstream spend is budgeted for early stage projects supporting potential future developments. The company will continue to monitor crude oil market conditions and expects to further restrict capital outlays should oil price conditions deteriorate.

Worldwide downstream spending in 2019 is estimated to be $2.5 billion, with $1.5 billion estimated for projects in the United States.

Investments in technology businesses and other corporate operations in 2019 are budgeted at $0.2 billion.

Noncontrolling Interests The company had noncontrolling interests of $1.1 billion at December 31, 2018 and $1.2 billion at December 31, 2017. Distributions to noncontrolling interests totaled $91 million and $78 million in 2018 and 2017, respectively.

Pension Obligations Information related to pension plan contributions is included beginning on page 81 in Note 22, Employee Benefit Plans, under the heading “Cash Contributions and Benefit Payments.”

Financial Ratios

	At December 31		
	2018	2017	2016
Current Ratio	1.3	1.0	0.9
Interest Coverage Ratio	23.4	10.7	(2.6)
Debt Ratio	18.2 %	20.7 %	24.1 %

Current Ratio Current assets divided by current liabilities, which indicates the company’s ability to repay its short-term liabilities with short-term assets. The current ratio in all periods was adversely affected by the fact that Chevron’s inventories are valued on a last-in, first-out basis. At year-end 2018, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $5.1 billion.

Interest Coverage Ratio Income before income tax expense, plus interest and debt expense and amortization of capitalized interest, less net income attributable to noncontrolling interests, divided by before-tax interest costs. This ratio indicates the company’s ability to pay interest on outstanding debt. The company’s interest coverage ratio in 2018 was higher than 2017 and 2016 due to higher income.

Debt Ratio Total debt as a percentage of total debt plus Chevron Corporation Stockholders' Equity, which indicates the company’s leverage. The company's debt ratio was 18.2 percent at year-end 2018, compared with 20.7 percent and 24.1 percent at year-end 2017 and 2016, respectively.

Off-Balance-Sheet Arrangements, Contractual Obligations, Guarantees and Other Contingencies

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements Information related to these matters is included on page 86 in Note 23, Other Contingencies and Commitments.

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The following table summarizes the company's significant contractual obligations:

Millions of dollars	Payments Due by Period				
	Total[1]	2019	2020-2021	2022-2023	After 2023
On Balance Sheet:[2]					
Short-Term Debt[3]	$5,727	$5,727	$ —	$ —	$ —
Long-Term Debt[3, 4]	28,630	—	17,226	7,053	4,351
Noncancelable Capital Lease Obligations	233	30	39	32	132
Interest	4,736	801	1,278	936	1,721
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,159	540	870	408	341
Throughput and Take-or-Pay Agreements[5]	7,797	773	1,523	1,208	4,293
Other Unconditional Purchase Obligations[5]	2,526	565	963	569	429

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 22 beginning on page 81.

2 Does not include amounts related to the company's income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates of the periods in which such liabilities may become payable. The company does not expect settlement of such liabilities to have a material effect on its consolidated financial position or liquidity in any single period.

3 $9.9 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2020–2021 period. The amounts represent only the principal balance.

4 Excludes capital lease obligations.

5 Does not include commodity purchase obligations that are not fixed or determinable. These obligations are generally monetized in a relatively short period of time through sales transactions or similar agreements with third parties. Examples include obligations to purchase LNG, regasified natural gas and refinery products at indexed prices.

As part of the implementation of ASU 2016-02 (Leases) effective January 1, 2019, the company will reclassify some contracts, currently incorporated into the unconditional purchase obligations disclosure, as operating leases in first quarter 2019 results.

Direct Guarantees

Millions of dollars	Commitment Expiration by Period				
	Total	2019	2020-2021	2022-2023	After 2023
Guarantee of nonconsolidated affiliate or joint-venture obligations	$968	$264	$ 489	$ 77	$138

Additional information related to guarantees is included on page 86 in Note 23, Other Contingencies and Commitments.

Indemnifications Information related to indemnifications is included on page 86 in Note 23, Other Contingencies and Commitments.

Financial and Derivative Instrument Market Risk

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A.

Derivative Commodity Instruments Chevron is exposed to market risks related to the price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks. The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited

trading purposes. The results of these activities were not material to the company's financial position, results of operations or cash flows in 2018.

The company's market exposure positions are monitored on a daily basis by an internal Risk Control group in accordance with the company's risk management policies. The company's risk management practices and its compliance with policies are reviewed by the Audit Committee of the company's Board of Directors.

Derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes. The change in fair value of Chevron's derivative commodity instruments in 2018 was not material to the company's results of operations.

The company uses the Monte Carlo simulation method as its Value-at-Risk (VaR) model to estimate the maximum potential loss in fair value, at the 95% confidence level with a one-day holding period, from the effect of adverse changes in market

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conditions on derivative commodity instruments held or issued. Based on these inputs, the VaR for the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2018 and 2017 was not material to the company's cash flows or results of operations.

Foreign Currency The company may enter into foreign currency derivative contracts to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments. The foreign currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open foreign currency derivative contracts at December 31, 2018.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Interest rate swaps, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2018, the company had no interest rate swaps.

Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements and long-term purchase agreements. Refer to "Other Information" on page 70, in Note 14, Investments and Advances, for further discussion. Management believes these agreements have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

Litigation and Other Contingencies

MTBE Information related to methyl tertiary butyl ether (MTBE) matters is included on page 70 in Note 15 under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 15 under the heading "Ecuador," beginning on page 70.

Environmental The following table displays the annual changes to the company's before-tax environmental remediation reserves, including those for federal Superfund sites and analogous sites under state laws.

Millions of dollars	2018	2017	2016
Balance at January 1	$1,429	$1,467	$1,578
Net Additions	197	323	260
Expenditures	(299)	(361)	(371)
Balance at December 31	$1,327	$1,429	$1,467

The company records asset retirement obligations when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. These asset retirement obligations include costs related to environmental issues. The liability balance of approximately $14.1 billion for asset retirement obligations at year-end 2018 related primarily to upstream properties.

For the company's other ongoing operating assets, such as refineries and chemicals facilities, no provisions are made for exit or cleanup costs that may be required when such assets reach the end of their useful lives unless a decision to sell or otherwise abandon the facility has been made, as the indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the asset retirement obligation.

Refer to the discussion below for additional information on environmental matters and their impact on Chevron, and on the company's 2018 environmental expenditures. Refer to Note 23 on page 86 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 24 on page 88 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 20, Accounting for Suspended Exploratory Wells, beginning on page 79.

Income Taxes Information related to income tax contingencies is included on pages 74 through 76 in Note 16 and page 86 in Note 23 under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page 87 in Note 23 to the Consolidated Financial Statements under the heading "Other Contingencies."

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Environmental Matters

The company is subject to various international, federal, state and local environmental, health and safety laws, regulations and market-based programs. These laws, regulations and programs continue to evolve and are expected to increase in both number and complexity over time and govern not only the manner in which the company conducts its operations, but also the products it sells. For example, international agreements and national, regional, and state legislation (e.g., California AB32, SB32 and AB398) and regulatory measures that aim to limit or reduce greenhouse gas (GHG) emissions are currently in various stages of implementation. Consideration of GHG issues and the responses to those issues through international agreements and national, regional or state legislation or regulations are integrated into the company’s strategy and planning, capital investment reviews and risk management tools and processes, where applicable. They are also factored into the company’s long-range supply, demand and energy price forecasts. These forecasts reflect long-range effects from renewable fuel penetration, energy efficiency standards, climate-related policy actions, and demand response to oil and natural gas prices. In addition, legislation and regulations intended to address hydraulic fracturing also continue to evolve at the national, state and local levels. Refer to “Risk Factors” in Part I, Item 1A, on pages 18 through 21 for a discussion of some of the inherent risks of increasingly restrictive environmental and other regulation that could materially impact the company’s results of operations or financial condition.

Most of the costs of complying with existing laws and regulations pertaining to company operations and products are embedded in the normal costs of doing business. However, it is not possible to predict with certainty the amount of additional investments in new or existing technology or facilities or the amounts of increased operating costs to be incurred in the future to: prevent, control, reduce or eliminate releases of hazardous materials or other pollutants into the environment; remediate and restore areas damaged by prior releases of hazardous materials; or comply with new environmental laws or regulations. Although these costs may be significant to the results of operations in any single period, the company does not presently expect them to have a material adverse effect on the company's liquidity or financial position.

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. The company may incur expenses for corrective actions at various owned and previously owned facilities and at third-party-owned waste disposal sites used by the company. An obligation may arise when operations are closed or sold or at non-Chevron sites where company products have been handled or disposed of. Most of the expenditures to fulfill these obligations relate to facilities and sites where past operations followed practices and procedures that were considered acceptable at the time but now require investigative or remedial work or both to meet current standards.

Using definitions and guidelines established by the American Petroleum Institute, Chevron estimated its worldwide environmental spending in 2018 at approximately $2.0 billion for its consolidated companies. Included in these expenditures were approximately $0.5 billion of environmental capital expenditures and $1.5 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

For 2019, total worldwide environmental capital expenditures are estimated at $0.5 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

Critical Accounting Estimates and Assumptions

Management makes many estimates and assumptions in the application of generally accepted accounting principles (GAAP) that may have a material impact on the company’s consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. Such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on management’s experience and other information available prior to the issuance of the financial statements. Materially different results can occur as circumstances change and additional information becomes known.

The discussion in this section of “critical” accounting estimates and assumptions is according to the disclosure guidelines of the Securities and Exchange Commission (SEC), wherein:

1. the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters, or the susceptibility of such matters to change; and
2. the impact of the estimates and assumptions on the company's financial condition or operating performance is material.

The development and selection of accounting estimates and assumptions, including those deemed "critical," and the associated disclosures in this discussion have been discussed by management with the Audit Committee of the Board of Directors. The areas of accounting and the associated "critical" estimates and assumptions made by the company are as follows:

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Oil and Gas Reserves Crude oil and natural gas reserves are estimates of future production that impact certain asset and expense accounts included in the Consolidated Financial Statements. Proved reserves are the estimated quantities of oil and gas that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future under existing economic conditions, operating methods and government regulations. Proved reserves include both developed and undeveloped volumes. Proved developed reserves represent volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for recompletion. Variables impacting Chevron's estimated volumes of crude oil and natural gas reserves include field performance, available technology, commodity prices, and development and production costs.

The estimates of crude oil and natural gas reserves are important to the timing of expense recognition for costs incurred and to the valuation of certain oil and gas producing assets. Impacts of oil and gas reserves on Chevron's Consolidated Financial Statements, using the successful efforts method of accounting, include the following:

1. Amortization - Capitalized exploratory drilling and development costs are depreciated on a unit-of-production (UOP) basis using proved developed reserves. Acquisition costs of proved properties are amortized on a UOP basis using total proved reserves. During 2018, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for oil and gas properties was $14.8 billion, and proved developed reserves at the beginning of 2018 were 6.1 billion barrels for consolidated companies. If the estimates of proved reserves used in the UOP calculations for consolidated operations had been lower by 5 percent across all oil and gas properties, UOP DD&A in 2018 would have increased by approximately $800 million.
2. Impairment - Oil and gas reserves are used in assessing oil and gas producing properties for impairment. A significant reduction in the estimated reserves of a property would trigger an impairment review. Proved reserves (and, in some cases, a portion of unproved resources) are used to estimate future production volumes in the cash flow model. For a further discussion of estimates and assumptions used in impairment assessments, see Impairment of Properties, Plant and Equipment and Investments in Affiliates below.

Refer to Table V, “Reserve Quantity Information,” beginning on page 95, for the changes in proved reserve estimates for the three years ended December 31, 2018, and to Table VII, “Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves” on page 101 for estimates of proved reserve values for each of the three years ended December 31, 2018.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1, beginning on page 55, which includes a description of the “successful efforts” method of accounting for oil and gas exploration and production activities.

Impairment of Properties, Plant and Equipment and Investments in Affiliates The company assesses its properties, plant and equipment (PP&E) for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its estimated fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters, such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles, and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, commodity chemicals and refined products. However, the impairment reviews and calculations are based on assumptions that are generally consistent with the company’s business plans and long-term investment decisions. Refer also to the discussion of impairments of properties, plant and equipment in Note 17 on page 77 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page 55.

The company routinely performs impairment reviews when triggering events arise to determine whether any write-down in the carrying value of an asset or asset group is required. For example, when significant downward revisions to crude oil and natural gas reserves are made for any single field or concession, an impairment review is

performed to determine if the carrying value of the asset remains recoverable. Similarly, a significant downward revision in the company's crude oil or natural gas price outlook would trigger impairment reviews for impacted upstream assets. In addition, impairments could occur due to changes in national, state or local environmental regulations or laws, including those designed to stop or impede the development or production of oil and gas. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision

is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets' associated carrying values.
Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for impairment when the fair value of the investment falls below the company's carrying value. When this occurs, a determination must be made as to whether this loss is other-than-temporary, in which case the investment is impaired. Because of the number of differing assumptions potentially affecting whether an investment is impaired in any period or the amount of the impairment, a sensitivity analysis is not practicable.
No individually material impairments of PP&E or Investments were recorded for 2018 or 2017. The company reported impairments for certain oil and gas properties in Brazil and the United States during 2016 due to reservoir performance and lower crude oil prices. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired, or resulted in larger impacts on impaired assets.
Asset Retirement Obligations In the determination of fair value for an asset retirement obligation (ARO), the company uses various assumptions and judgments, including such factors as the existence of a legal obligation, estimated amounts and timing of settlements, discount and inflation rates, and the expected impact of advances in technology and process improvements. A sensitivity analysis of the ARO impact on earnings for 2018 is not practicable, given the broad range of the company's long-lived assets and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions would have reduced estimated future obligations, thereby lowering accretion expense and amortization costs, whereas unfavorable changes would have the opposite effect. Refer to Note 24 on page 88 for additional discussions on asset retirement obligations.
Pension and Other Postretirement Benefit Plans Note 22, beginning on page 81, includes information on the funded status of the company's pension and other postretirement benefit (OPEB) plans reflected on the Consolidated Balance Sheet; the components of pension and OPEB expense reflected on the Consolidated Statement of Income; and the related underlying assumptions.
The determination of pension plan expense and obligations is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. Critical assumptions in determining expense and obligations for OPEB plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, are the discount rate and the assumed health care cost-trend rates. Information related to the company's processes to develop these assumptions is included on page 83 in Note 22 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes beyond the company's control.
For 2018, the company used an expected long-term rate of return of 6.75 percent and a discount rate for service costs of 3.7 percent and a discount rate for interest cost of 3.0 percent for U.S. pension plans. The actual return for 2018 was negative. For the 10 years ended December 31, 2018, actual asset returns averaged 7.9 percent for these plans. Additionally, with the exception of three years within this 10-year period, actual asset returns for these plans equaled or exceeded 6.75 percent during each year.
Total pension expense for 2018 was $1.1 billion. An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in this assumption for the company's primary U.S. pension plan, which accounted for about 63 percent of companywide pension expense, would have reduced total pension plan expense for 2018 by approximately $83 million. A 1 percent increase in the discount rates for this same plan would have reduced pension expense for 2018 by approximately $271 million.
The aggregate funded status recognized at December 31, 2018, was a net liability of approximately $3.9 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At

December 31, 2018, the company used a discount rate of 4.2 percent to measure the obligations for the U.S. pension plans. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan, which accounted for about 62 percent of the companywide pension obligation, would have reduced the plan obligation by approximately $339 million, and would have decreased the plan's underfunded status from approximately $1.8 billion to $1.4 billion.

For the company's OPEB plans, expense for 2018 was $123 million, and the total liability, all unfunded at the end of 2018, was $2.4 billion. For the main U.S. OPEB plan, the company used a discount rate for service cost of 3.8 percent and a discount rate for interest cost of 3.2 percent to measure expense in 2018, and a 4.3 percent discount rate to measure the benefit obligations at December 31, 2018. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2018 OPEB expense and OPEB liabilities at the end of 2018. For information on the sensitivity of the health care cost-trend rate, refer to page 83 in Note 22 under the heading "Other Benefit Assumptions."

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are included in actuarial gain/loss. Refer to page 82 in Note 22 for a description of the method used to amortize the $4.6 billion of before-tax actuarial losses recorded by the company as of December 31, 2018, and an estimate of the costs to be recognized in expense during 2019. In addition, information related to company contributions is included on page 85 in Note 22 under the heading "Cash Contributions and Benefit Payments."

Contingent Losses Management also makes judgments and estimates in recording liabilities for claims, litigation, tax matters and environmental remediation. Actual costs can frequently vary from estimates for a variety of reasons. For example, the costs for settlement of claims and litigation can vary from estimates based on differing interpretations of laws, opinions on culpability and assessments on the amount of damages. Similarly, liabilities for environmental remediation are subject to change because of changes in laws, regulations and their interpretation, the determination of additional information on the extent and nature of site contamination, and improvements in technology.

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is "more likely than not" (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 23 beginning on page 86. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2018.

An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in recording these liabilities is not practicable because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, both in terms of the probability of loss and the estimates of such loss.

New Accounting Standards

Refer to Note 4 beginning on page 60 for information regarding new accounting standards.

Quarterly Results
Unaudited

	2018				2017			
Millions of dollars, except per-share amounts	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q
Revenues and Other Income								
Sales and other operating revenues[1]	$40,338	$42,105	$40,491	$35,968	$36,381	$33,892	$32,877	$31,524
Income from equity affiliates	1,642	1,555	1,493	1,637	936	1,036	1,316	1,150
Other income	372	327	252	159	299	1,277	287	747
Total Revenues and Other Income	42,352	43,987	42,236	37,764	37,616	36,205	34,480	33,421
Costs and Other Deductions								
Purchased crude oil and products	23,920	24,681	24,744	21,233	21,158	18,776	18,325	17,506
Operating expenses [2]	5,645	4,985	5,213	4,701	5,106	4,845	4,590	4,586
Selling, general and administrative expenses [2]	1,080	1,018	1,017	723	1,262	1,111	927	810
Exploration expenses	250	625	177	158	356	239	125	144
Depreciation, depletion and amortization	5,252	5,380	4,498	4,289	4,735	5,109	5,311	4,194
Taxes other than on income[1]	901	1,259	1,363	1,344	3,182	3,213	3,065	2,871
Interest and debt expense	190	182	217	159	173	35	48	51
Other components of net periodic benefit costs[2]	216	158	102	84	163	219	136	130
Total Costs and Other Deductions	37,454	38,288	37,331	32,691	36,135	33,547	32,527	30,292
Income (Loss) Before Income Tax Expense	4,898	5,699	4,905	5,073	1,481	2,658	1,953	3,129
Income Tax Expense (Benefit)	1,175	1,643	1,483	1,414	(1,637)	672	487	430
Net Income (Loss)	$3,723	$4,056	$3,422	$3,659	$3,118	$1,986	$1,466	$2,699
Less: Net income attributable to noncontrolling interests	(7)	9	13	21	7	34	16	17
Net Income (Loss) Attributable to Chevron Corporation	$3,730	$4,047	$3,409	$3,638	$3,111	$1,952	$1,450	$2,682
Per Share of Common Stock								
Net Income (Loss) Attributable to Chevron Corporation								
– Basic	$1.97	$2.13	$1.79	$1.92	$1.65	$1.03	$0.77	$1.43
– Diluted	$1.95	$2.11	$1.78	$1.90	$1.64	$1.03	$0.77	$1.41
Dividends	$1.12	$1.12	$1.12	$1.12	$1.08	$1.08	$1.08	$1.08
[1] Includes excise, value-added and similar taxes:	$—	$—	$—	$—	$1,874	$1,867	$1,771	$1,677

Beginning in 2018, excises taxes are netted in "Taxes other than on income" in accordance with ASU 2014-09. Refer to Note 25, "Revenue" beginning on page 88.
[2] 2017 adjusted to conform to ASU 2017-07. Refer to Note 4, "New Accounting Standards" beginning on page 60.

Management’s Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

Management of Chevron Corporation is responsible for preparing the accompanying consolidated financial statements and the related information appearing in this report. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and fairly represent the transactions and financial position of the company. The financial statements include amounts that are based on management’s best estimates and judgments.

As stated in its report included herein, the independent registered public accounting firm of PricewaterhouseCoopers LLP has audited the company’s consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Board of Directors of Chevron has an Audit Committee composed of directors who are not officers or employees of the company. The Audit Committee meets regularly with members of management, the internal auditors and the independent registered public accounting firm to review accounting, internal control, auditing and financial reporting matters. Both the internal auditors and the independent registered public accounting firm have free and direct access to the Audit Committee without the presence of management.

The company's management has evaluated, with the participation of the Chief Executive Officer and Chief Financial Officer, the effectiveness of the company's disclosure controls and procedures (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2018. Based on that evaluation, management concluded that the company's disclosure controls are effective in ensuring that information required to be recorded, processed, summarized and reported, are done within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms.

Management’s Report on Internal Control Over Financial Reporting

The company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in the Exchange Act Rules 13a-15(f) and 15d-15(f). The company’s management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company’s internal control over financial reporting based on the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of this evaluation, the company’s management concluded that internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the company’s internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

Michael K. Wirth	Patricia E. Yarrington	Jeanette L. Ourada
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 22, 2019

Report of Independent Registered Public Accounting Firm
To the Board of Directors and Shareholders of Chevron Corporation:
Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated balance sheets of Chevron Corporation and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2018, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).
In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.
Basis for Opinions
The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.
Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.
Definition and Limitations of Internal Control over Financial Reporting
A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally

accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

San Francisco, California
February 22, 2019
We have served as the Company's auditor since 1935.

Consolidated Statement of Income
Millions of dollars, except per-share amounts

	Year ended December 31		
	2018	2017	2016
Revenues and Other Income			
Sales and other operating revenues[1]	$158,902	$134,674	$110,215
Income from equity affiliates	6,327	4,438	2,661
Other income	1,110	2,610	1,596
Total Revenues and Other Income	166,339	141,722	114,472
Costs and Other Deductions			
Purchased crude oil and products	94,578	75,765	59,321
Operating expenses[2]	20,544	19,127	19,902
Selling, general and administrative expenses[2]	3,838	4,110	4,305
Exploration expenses	1,210	864	1,033
Depreciation, depletion and amortization	19,419	19,349	19,457
Taxes other than on income[1]	4,867	12,331	11,668
Interest and debt expense	748	307	201
Other components of net periodic benefit costs[2]	560	648	745
Total Costs and Other Deductions	145,764	132,501	