



2017 annual report

human energy®



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**the permian basin
is one of the most
prolific oil and natural
gas geologic basins in
the United States**

chevron resources*

**11.2 billion
barrels**

of net unrisked
oil-equivalent Permian Basin
resources in 2017

**permian
unconventional
production**

181,000

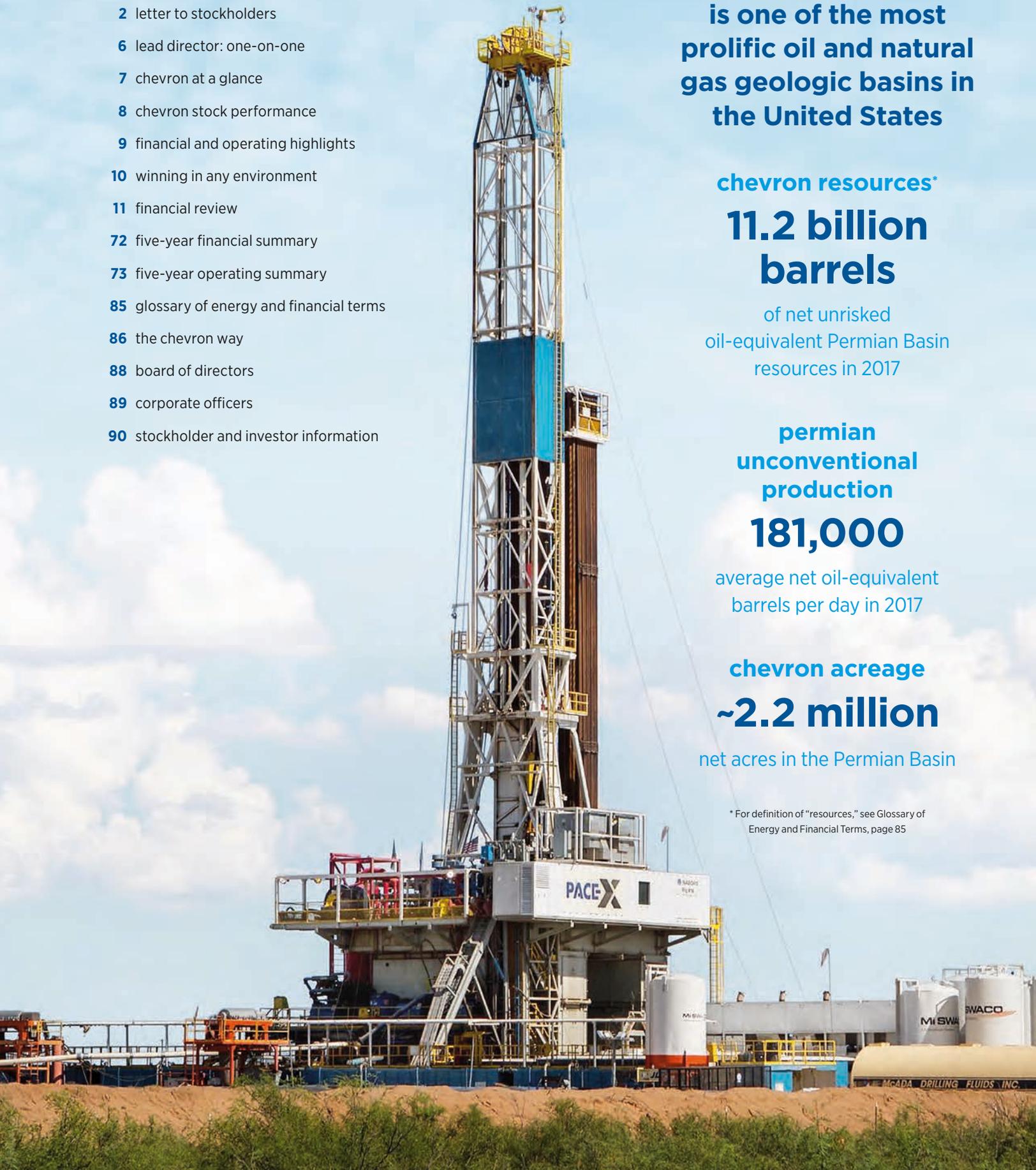
average net oil-equivalent
barrels per day in 2017

chevron acreage

~2.2 million

net acres in the Permian Basin

* For definition of "resources," see Glossary of
Energy and Financial Terms, page 85



powering the world forward

Chevron has emerged from the changes that have reshaped the world's energy landscape as a stronger, leaner and more agile enterprise. Today, we stand ready to win in any business environment.

Each day, our people deliver the energy that billions around the world rely on for the most basic of human needs, along with the social and economic progress that reliable, affordable energy provides. Their commitment – along with our pursuit of technological and scientific innovations that push the frontiers of our industry – positions us well to meet the challenges of this responsibility with skill, ingenuity and an unwavering commitment to the vision, values and strategies of The Chevron Way.

Chevron's portfolio of assets is strong. Our Upstream business is resilient, built to deliver short-cycle, high-return projects as well as long-term resource sustainability. Our Downstream & Chemicals business is highly competitive, with a global portfolio that is strategically focused to leverage areas of strength. Our Midstream organization delivers the commercial, technical and operational expertise that enhances results in Upstream and in Downstream & Chemicals.

As the world's population continues to grow, so, too, will global demand for energy. We are looking toward the future – working to develop generations of talent inside and outside our company; proudly and responsibly leading in conventional energy sources while exploring and evaluating new and emerging energy solutions; and leveraging technology to improve efficiency and productivity while solving the most complex energy challenges of our time. And above all, we are creating value for our stockholders, customers, partners and communities.

The right way. The responsible way. The Chevron Way.

A digital version of this report is available. www.chevron.com/annualreport2017

On the cover: Chevron's Wheatstone Project in Australia, which achieved its first liquefied natural gas (LNG) production in October 2017, reinforces Chevron's position as a top natural gas supplier and LNG operator in the Asia-Pacific region. Wheatstone is also making a significant economic contribution to the long-term future of Australia through jobs, government revenues, and local goods and services.

On this page: Driven by innovations in well design and applications of new technology, Chevron's industry-leading shale and tight rock position in the Permian Basin of West Texas and southern New Mexico exceeded expectations in 2017, increasing production by 35 percent over 2016.



A man in a dark suit and pink tie is walking in a modern office hallway. He is looking slightly to his right. The hallway has a polished floor that reflects the light. The background shows a large window with a view of a city.

to our stockholders

The contributions of the energy industry to economic development have enabled the greatest advancements in living standards in recorded history. Over the course of nearly 140 years, Chevron has become a leader in helping improve the communities we touch – reducing energy poverty, driving economic and social development, improving health and education, delivering the benefits of modern life, and working to advance human progress for billions around the world, in developed and developing countries alike. Our leadership is a profound source of pride.

We take seriously our responsibility to answer the call of those who aspire to a better today – even as we continuously innovate to solve the energy challenges of tomorrow. That is why we are anchored to, and guided by, the vision, values and strategies of The Chevron Way. We strive to operate as *the* global energy company most admired for its people, partnership and performance. We are committed to business and enterprise strategies that enhance our ability to deliver industry-leading results and superior stockholder value in any business environment. And most important, we are united by our purpose: enabling human progress by developing the energy that improves lives and powers the world forward.

Delivering on our purpose requires relationships built upon trust and integrity throughout the world. So just as important as what we do is how we do it, through ethical and responsible actions that support and protect our workforce, our stakeholders, the communities where we operate and the environment, while delivering lasting and sustainable value to our stockholders. This is our definition of leading the right way. The responsible way. The Chevron Way. (See pages 86 and 87.)

At the heart of Chevron are a dedicated, innovative and talented global workforce and a Board of Directors that is engaged with leadership to oversee strategic decisions and to manage the wide array of risks inherent to our business.

In 2017, the world economy grew at its quickest pace in nearly five years, providing strong support to oil and gas demand. The combination of healthy demand growth and OPEC production cuts reduced the surplus in global oil markets, and China's actions to reduce air pollution and curb coal use supported demand in liquefied natural gas (LNG) markets.

Meanwhile, heightened geopolitical tensions throughout the world added uncertainty to markets, with ongoing tensions on the Korean Peninsula, continued strain in the Middle East and challenging economic conditions across oil exporting economies. The U.S. Congress passed the first comprehensive tax reform legislation in decades and began work on regulatory reform, providing renewed optimism for the U.S. economy.

Overall, oil and gas market conditions improved in 2017, and hydrocarbons are projected to play an important role in fueling the world economy for decades to come. Chevron's actions to bring on line new production from the Permian Basin in the United States and from our major capital projects in Australia helped meet growing global demand in 2017 and supported our aim of being a reliable supplier of the affordable energy the world needs in order to prosper.

During the downturn in commodity prices that began in 2014, we adjusted to challenging conditions, and in 2017, we delivered on our commitments to generate winning performance in any price environment. A key objective for 2017 was to become cash neutral – balance cash coming in and cash going out – in an environment of lower commodity prices. Full-year cash flow from operations was \$20.5 billion, and we were cash balanced without asset sales. This momentum continues as we move into 2018.

In 2017, we improved returns by further reducing expenses and by generating increased revenues as we brought projects on line. At the same time, our capital spending continued to shift toward shorter-cycle, high-return investments in unconventional oil and gas.

We continued to unlock value from our industry-leading portfolio of opportunities, including legacy positions in Australia, Kazakhstan and the Permian Basin. We captured the benefits of being an integrated energy company with strong earnings, cash flow and returns from our Downstream & Chemicals business.

Our full-year 2017 net income was \$9.2 billion, up \$9.7 billion from a loss in 2016. Our sales and other operating revenue was \$134.7 billion, up \$24.5 billion from 2016. We achieved a 5.0 percent return on capital employed.

2017 total net income
\$9.2 billion

in 2017, chevron's annual per-share dividend payout increased for the 30th consecutive year

Chevron's first financial priority is maintaining and growing the dividend when we can sustainably support the increase with cash flow and earnings. In 2017, our annual per-share dividend payout increased for the 30th consecutive year. We also strengthened our balance sheet – our year-end debt ratio was 20.7 percent, down from 24.1 percent at year-end 2016.

Our performance reflected the actions we took to ensure our competitiveness in any operating environment. Our priorities were to complete and start up projects under construction, reduce capital spending and operating expenses, selectively sell assets, and operate safely and reliably.

In 2017, we met those priorities. We finished construction of key major capital projects. We reduced capital spending to \$18.8 billion from \$22.4 billion in 2016. Since 2013, we've reduced our capital spending from a peak of \$41.9 billion. We also lowered operating expenses by \$1.1 billion from 2016. We met our 2016–2017 target for asset sales, receiving total proceeds of \$8 billion. And our steadfast commitment to eliminate high-consequence incidents continued.

In 2017, our Upstream business reported worldwide net production of 2.7 million oil-equivalent barrels per day, up more than 5 percent from 2016. We added approximately 1.54 billion barrels of net oil-equivalent proved reserves, replacing approximately 155 percent of production. In Australia, we continued to ramp up LNG production by bringing on line Gorgon Train 3 and Wheatstone Train 1. We ramped up production at Gorgon Trains 1 and 2 and at Jack/St. Malo in the U.S. Gulf of Mexico. The Hebron Project, our nonoperated joint venture in Canada, started production in 2017. In Kazakhstan,

we continued construction on the Future Growth Project and Wellhead Pressure Management Project. Production from our shale and tight rock activity in the Permian Basin exceeded expectations, driven by innovations in well design, applications of new technology, continued improvement in well drilling and completions, and an increase in long-lateral well inventory through optimization of our land position.

Chevron's 2017 results reflected strong performance from our Downstream & Chemicals business. In keeping with our strategic growth plans, we entered the retail fuel market in Mexico. Our joint venture Chevron Phillips Chemical Co. reached important milestones at its major U.S. Gulf Coast expansion, helping meet increased global petrochemicals demand and supporting our growth strategy. Chevron Oronite's Singapore plant completed its carboxylate project, which will double worldwide production capacity of this important lubricant additive. The modernization project at our Richmond Refinery, in California, met its construction milestones for the year and is on track to start up in 2018.

Our Midstream organization achieved a significant milestone by delivering the first LNG cargo from Wheatstone to customers in Japan. We also completed the largest shipbuilding and fleet modernization program in recent Chevron history, taking delivery of our fifth and sixth LNG carriers.

Chevron is in the business of progress – providing the energy to help local communities and economies grow and thrive. We know that our role in supplying the reliable, affordable and ever cleaner energy that the world needs is crucial, and we strive to deliver on our commitments. Each year, we invest tens of billions of dollars in jobs, goods and services in the communities around the world where we operate. Our strategic partnerships and social investments represent further important contributions to community prosperity. Over the past five years, we've made more than \$1.1 billion in social investments globally, consistently placing Chevron in the top quartile of Fortune 100 companies in these investments.

**over the last five years
chevron invested**

\$167 billion

in global goods and services

\$1.1 billion

in global social investments

In health, environment and safety for 2017, we maintained industry-leading personal safety rates and outperformed targets for several core metrics. To advance our focus on

eliminating high-consequence incidents and impacts, we developed and deployed tools to assure that safeguards are in place and functioning before beginning high-risk work.

We recognize that climate change is a subject of growing interest for investors, stakeholders and the public. In 2017, we engaged with our stockholders to better understand their questions about climate change related to our business.



45 ESG*
engagements

**representing 36% of chevron common stock
(683 million shares)**

*Environmental, social and governance

In response, we have published a new, more in-depth report that addresses our framework for incorporating climate change into our governance, risk management, strategy, and actions and investments. www.chevron.com/climate-change-resilience

In our annual Corporate Responsibility Report, we highlight key environmental, social and governance issues and performance. www.chevron.com/cr

As we look to the future, there is much we do not know. But a few things are certain. Populations will grow, incomes will rise and people will strive for better lives. Reliable, affordable and ever cleaner energy is essential to support this progress. The world's population is expected to increase by 1.7 billion people by 2040, and global energy demand is projected to increase by nearly 30 percent over that period. Yet even today, more than a billion people around the world have little or no access to reliable, affordable energy and the human progress it enables. We cannot leave them behind in our pursuit of the future.

Oil and natural gas are among the most reliable and affordable forms of energy available across the globe today and are forecast to be a major part of the world's energy portfolio for the foreseeable future.

The world also wants cleaner energy. We continue to make strides in reducing our environmental impact and finding ways to deliver smarter, cleaner energy production. At the same time, we continue to evaluate emerging and future sources of energy and the role they should play in Chevron's portfolio.

Chevron is an energy company built for the future. Our long, proud history, our commitment to our social purpose, our global partnerships and our outstanding portfolio of assets give us a powerful advantage as we compete in the ever-evolving market for energy. Yet Chevron's greatest strength is our people.

For generations, Chevron has developed and deployed world-class talent across many fields of science and technology to solve some of our most complex and pressing challenges. Individuals and teams across our company are examining the questions of today and the opportunities of tomorrow, pushing boundaries to ensure we deliver on our promises to our stockholders, our partners and our global societies.

It was the strength of our people and their commitment to our purpose that enabled Chevron to navigate the pressure of falling commodity prices and expanding supply during the Great Depression; discover crude oil in the desert of Saudi Arabia; help fuel the Allies to victory in World War II; become the first Western energy company to enter newly independent Kazakhstan; and apply technology and innovation to find, produce and transport resources in ever-more-challenging global environments. It is this same strength and commitment that has maintained stability amid the challenge of the recent prolonged period of lower commodity prices. Looking ahead, it is this strength and commitment upon which we will build Chevron's success.

Chevron moves into the future with optimism and purpose, confident in our leadership role in developing the energy that unlocks the potential for progress and prosperity. In doing so, we are committed to delivering industry-leading results and superior stockholder value safely, responsibly and ethically in any operating environment.

Thank you for investing in Chevron.



Michael K. Wirth
Chairman of the Board and
Chief Executive Officer
February 22, 2018



John Watson's legacy

Under John Watson's leadership as Chairman of the Board and Chief Executive Officer for the past eight years, Chevron delivered outstanding performance. We produced industry-leading financial results, including ranking No. 1 in total stockholder return (TSR) relative to our peers and extending our record to 30 consecutive years of increased annual per-share dividend payouts. We also outperformed our competitors in key operational metrics, including personal safety and petroleum spill volume.

John oversaw major capital projects around the world that are growing production and generating cash flow for the future. He established Chevron as a leading competitor in North American unconventional oil and gas. During a prolonged decline in crude oil prices, John's steady leadership enabled Chevron to successfully navigate the downturn and emerge a stronger, leaner and more agile company.

To the public and to Chevron employees, he was a passionate advocate for the value that the oil and gas industry delivers to the world, saying often, "We are a noble business." To Chevron's workforce, John emphasized operating safely, reliably and ethically and stressed the importance of diversity, inclusion and leadership development as essential to delivering superior business results.

John Watson retired effective February 1, 2018. Because of his exemplary leadership, Chevron is strongly positioned for future success.

10.1% TSR*
ranked #1 relative to peers

*1/1/2010 - 1/31/2018

30 consecutive years
annual per-share dividend payout
increases as of 12/31/2017

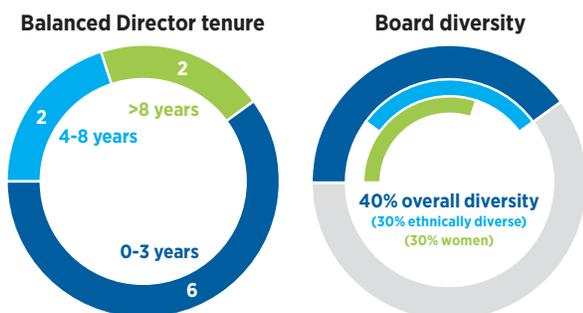
lead director: one-on-one

Lead Independent Director Ronald D. Sugar provides insight into how Chevron's Board of Directors puts the interest of stockholders first.



Q: Tell us how Chevron's Board sees its responsibility to represent the interests of stockholders.

A: Chevron's stockholders are represented by accomplished, diverse and independent Directors with experience in global business, public policy, finance, technology and environmental matters. Diversity of gender, ethnicity, age, skills and experience foster different perspectives that make our Board's oversight and decision making more effective. In addition, our Directors have the highest personal integrity and a deep interest in Chevron's underlying business.



As a Board, we hold Mike Wirth and his team accountable for running the business day-to-day, and we provide oversight on behalf of stockholders. We ensure that we have the right leadership in place and the right strategy moving forward and that we operate at a prudent level of business risk. We think independently, debate openly, but act cohesively to put the interests of our stockholders first.

Q: How does having Chevron's CEO also serve as Chairman work in the best interest of stockholders?

A: Chevron's by-laws require that our independent Directors appoint a Chairman annually. We recently completed the management succession process that selected Mike Wirth as our new CEO and then carefully deliberated on whether he or another Director should serve as Chairman. We decided that Mike should also represent the Board as Chairman, given the broad scale and sensitivity of Chevron's interactions with governments and heads-of-state around the world. Our by-laws also call for a strong Lead Independent Director position to ensure that independent Directors exercise rigorous oversight

of the management of the company. As discussed in our Proxy Statement, the Lead Independent Director is invested with considerable authority to facilitate that oversight. Mike and I speak frequently, each with a clear understanding of his own role.

Q: What role does Chevron's Board play in oversight of strategy and managing risk?

A: Chevron is in a long-cycle, complex global business, and the Board must think about the future beyond current business conditions. It's our job to review, test, debate and, where necessary, adjust the company's business strategy. We examine internal and external views of energy market conditions, geopolitical developments, technology trends and competitor actions. This enables us to most effectively deploy our capital and human talent to achieve both near-term and longer-term stockholder objectives. To manage risk, Chevron's management employs a meticulous process to regularly identify and analyze threat scenarios and deploy appropriate mitigations. The full Board then conducts a comprehensive risk review to ensure that risk management systems are employed effectively across the company.

Q: What is the role of Chevron's Board in managing climate change risk?

A: Climate change is a growing area of interest for our investors and other stakeholders. We're committed to addressing the risks of climate change while delivering the energy that benefits societies and economies. Chevron's management integrates climate change considerations into its risk management, governance and business planning processes. The Board regularly assesses climate change risks and opportunities throughout the year. Climate change is also a frequent topic when management and members of the Board meet with stockholders. As a result of stockholder feedback, the Board recently endorsed a second, more detailed voluntary report on climate change related to Chevron.

www.chevron.com/climate-change-resilience

Q: Does Chevron meet directly with stockholders?

A: Yes, and we have done so regularly for many years. In 2017, an engagement team of Chevron senior executives and experts on compensation, environmental, social and governance issues conducted 45 discussions with stockholders representing 36 percent of Chevron's outstanding common stock. To better understand their points of view, the team also met with many of the groups who submitted proposals for our proxy. The engagement team then shared all the feedback from stockholders and proponents with the full Board. From time to time, other Directors and I also participate in such meetings. This firsthand participation has proved invaluable in bringing the voices of our owners back to our boardroom.

chevron at a glance

Chevron is one of the world's leading integrated energy companies. We explore for, produce and transport crude oil and natural gas; refine, market and distribute transportation fuels and lubricants; manufacture and sell petrochemicals and additives; and develop and deploy technologies that enhance business value in every aspect of the company's operations. Our success is driven by a dedicated, diverse and highly skilled global workforce, united by the vision, values and strategies of The Chevron Way and a commitment to deliver industry-leading results and superior stockholder value in any operating environment. We operate responsibly, applying advanced technologies, capturing new high-return opportunities, and producing returns in a socially and environmentally responsible manner. We take great pride in enabling human progress by developing the energy that improves lives and powers the world forward.

net oil-equivalent
daily production¹

2.7 million barrels

net oil-equivalent
proved reserves^{2, 3}

11.7 billion barrels

sales and other
operating revenues¹

\$134.7 billion

total assets²

\$253.8 billion

Photo: The Chevron-operated Tengizchevroil (TCO) joint venture in Kazakhstan continued construction in 2017 of the Future Growth Project-Wellhead Pressure Management Project (FGP-WPMP), designed to further increase total daily production from the supergiant Tengiz reservoir and maximize the ultimate recovery of resources. The FGP-WPMP is growing TCO's investments in Kazakhstan through many new jobs and large-scale use of local goods and services that are contributing to the regional and national economies. Shown here are multiwell pads, where rigs are now drilling the wells that will bring additional production to the existing trains.

1. Year ended December 31, 2017

2. At December 31, 2017

3. For definition of "reserves," see Glossary of Energy and Financial Terms, page 85



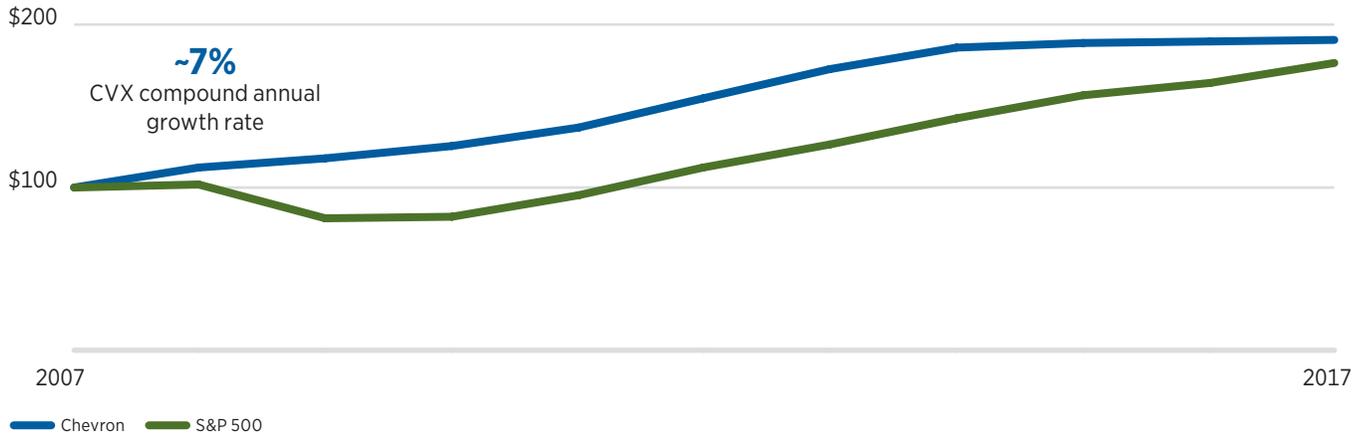
chevron stock performance

30 consecutive years

2017 marked the 30th consecutive year we increased the annual per-share dividend payout.

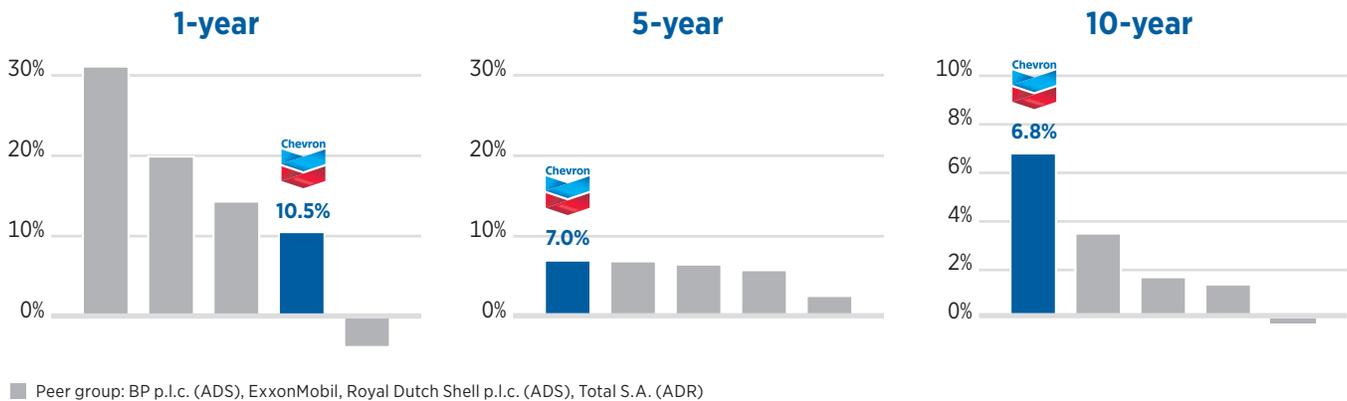
Indexed dividend growth

Basis 2007 = 100



Total stockholder returns*

(as of 12/31/2017)



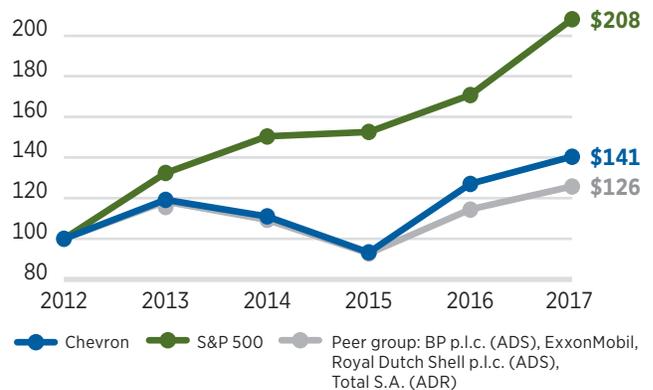
* Annualized total stockholder return as of 12/31/2017. Includes stock price appreciation and reinvested dividends when paid. For TSR comparison purposes, ADR/ADS prices and dividends are used for non-U.S.-based companies. Dividends include both cash and scrip share distributions.

Performance graph

The stock performance graph at right shows how an initial investment of \$100 in Chevron stock would have compared with an equal investment in the S&P 500 Index or the competitor peer group. The comparison covers a five-year period beginning December 31, 2012, and ending December 31, 2017, and for the peer group is weighted by market capitalization as of the beginning of each year. It includes the reinvestment of all dividends that an investor would be entitled to receive and is adjusted for stock splits. The interim measurement points show the value of \$100 invested on December 31, 2012, and as of the end of each year from 2013 through 2017.

Five-year cumulative total returns

(Calendar years ended December 31)



financial and operating highlights

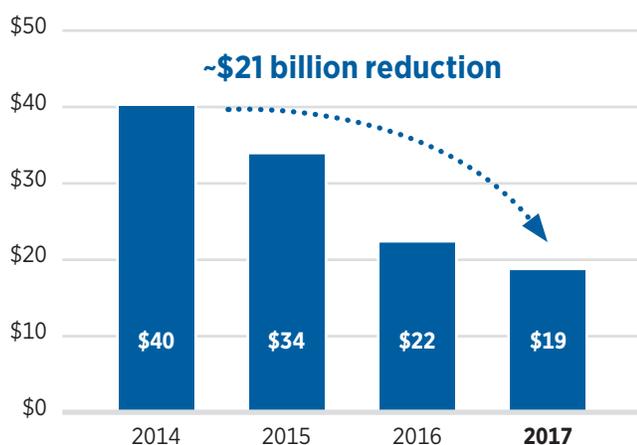
Financial highlights ¹	2017	2016	2015
Net income (loss) attributable to Chevron Corporation	\$ 9,195	\$ (497)	\$ 4,587
Sales and other operating revenues	\$ 134,674	\$ 110,215	\$ 129,925
Cash provided by operating activities	\$ 20,515	\$ 12,846	\$ 19,456
Capital and exploratory expenditures ²	\$ 18,821	\$ 22,428	\$ 33,979
Total assets at year-end	\$ 253,806	\$ 260,078	\$ 264,540*
Total debt and capital lease obligations at year-end	\$ 38,763	\$ 46,126	\$ 38,549*
Chevron Corporation stockholders' equity at year-end	\$ 148,124	\$ 145,556	\$ 152,716
Common shares outstanding at year-end (Thousands)	1,890,534	1,877,338	1,868,646
Per-share data			
Net income (loss) attributable to Chevron Corporation – diluted	\$ 4.85	\$ (0.27)	\$ 2.45
Cash dividends	\$ 4.32	\$ 4.29	\$ 4.28
Chevron Corporation stockholders' equity	\$ 78.35	\$ 77.53	\$ 81.73
Common stock price at year-end	\$ 125.19	\$ 117.70	\$ 89.96
Debt ratio	20.7%	24.1%	20.2%
Return on stockholders' equity	6.3%	(0.3)%	3.0%
Return on capital employed	5.0%	(0.1)%	2.5%

¹ Millions of dollars, except per-share amounts

² Includes equity in affiliates

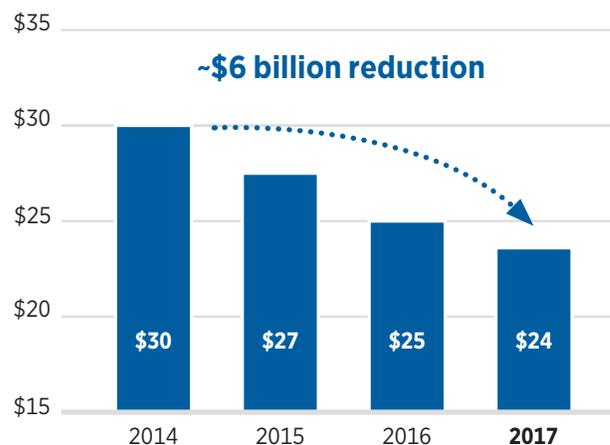
* 2015 presentations were adjusted to conform to ASU 2015-17 "Income Taxes – Balance Sheet Classification of Deferred Taxes" and ASU 2015-03 "Imputation of Interest – Simplifying the Presentation of Debt Issuance Costs"

Total capital and exploratory expenditures³ (Billion US\$)



³ Includes equity in affiliates

Operating expense and SG&A expense^{4,5} (Billion US\$)



⁴ Excludes affiliate spending

⁵ SG&A = selling, general and administrative expense

Operating highlights⁶

	2017	2016	2015
Net production of crude oil, condensate, NGLs and synthetic oil ⁷ (Thousands of barrels per day)	1,723	1,719	1,744
Net production of natural gas (Millions of cubic feet per day)	6,032	5,252	5,269
Total net oil-equivalent production (Thousands of oil-equivalent barrels per day)	2,728	2,594	2,622
Net proved reserves of crude oil, condensate, NGLs and synthetic oil ⁷ (Millions of barrels)	6,542	6,328	6,262
Net proved reserves of natural gas ⁸ (Billions of cubic feet)	30,736	28,760	29,437
Net proved oil-equivalent reserves ⁹ (Millions of barrels)	11,665	11,121	11,168
Refinery input (Thousands of barrels per day)	1,661	1,688	1,702
Sales of refined products (Thousands of barrels per day)	2,690	2,675	2,735
Number of employees at year-end ⁹	48,596	51,953	58,178

⁶ Includes equity in affiliates, except number of employees

⁷ NGLs = natural gas liquids

⁸ At year-end

⁹ Excludes service station personnel

winning in any environment

We know our investors expect industry-leading results and superior stockholder value in any business environment. We're committed to business and enterprise strategies to grow free cash flow, improve returns and deliver value to our stockholders, strategies which are listed below:

what we have

advantaged portfolio

sustainable at lower prices

strong balance sheet

exceptional workforce



what we will do

be returns-driven in capital allocation

get more out of assets

lower our cost structure

high-grade portfolio

grow production and cash margins



what investors get

superior total stockholder return, free cash flow growth and #1 priority: maintain and grow dividend

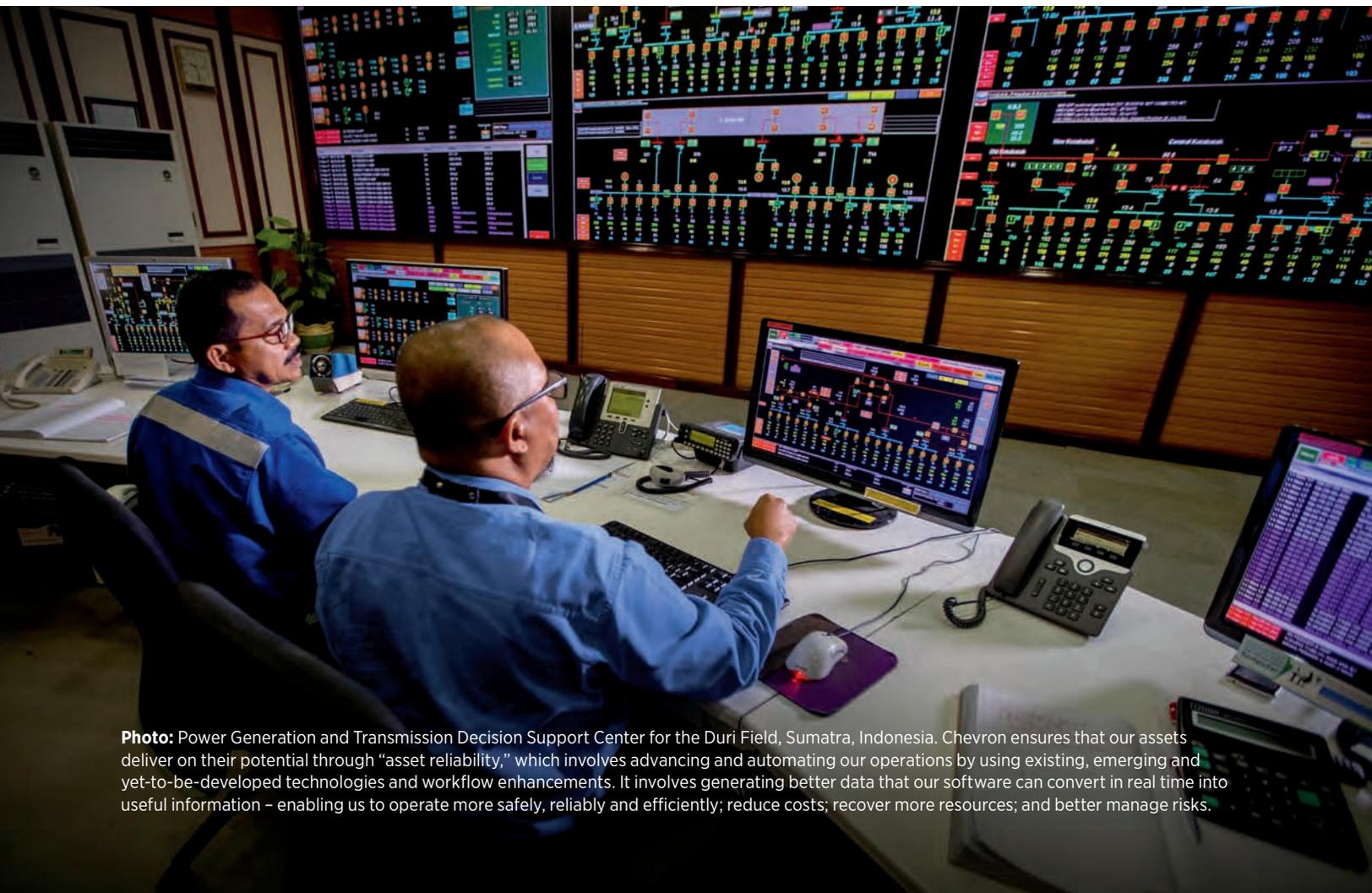


Photo: Power Generation and Transmission Decision Support Center for the Duri Field, Sumatra, Indonesia. Chevron ensures that our assets deliver on their potential through "asset reliability," which involves advancing and automating our operations by using existing, emerging and yet-to-be-developed technologies and workflow enhancements. It involves generating better data that our software can convert in real time into useful information – enabling us to operate more safely, reliably and efficiently; reduce costs; recover more resources; and better manage risks.

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

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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* 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,” “budgets,” “outlook,” “trends,” “guidance,” “focus,” “on schedule,” “on track,” “is slated,” “goals,” “objectives,” “strategies,” “opportunities” and similar 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 its 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, 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 impact of the 2017 U.S. tax legislation on the company’s future results; 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 19 through 22 of the company’s Annual Report on Form 10-K. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Key Financial Results

<i>Millions of dollars, except per-share amounts</i>	2017	2016	2015
Net Income (Loss) Attributable to Chevron Corporation	\$ 9,195	\$ (497)	\$ 4,587
Per Share Amounts:			
Net Income (Loss) Attributable to Chevron Corporation			
– Basic	\$ 4.88	\$ (0.27)	\$ 2.46
– Diluted	\$ 4.85	\$ (0.27)	\$ 2.45
Dividends	\$ 4.32	\$ 4.29	\$ 4.28
Sales and Other Operating Revenues	\$ 134,674	\$ 110,215	\$ 129,925
Return on:			
Capital Employed	5.0%	(0.1)%	2.5%
Stockholders' Equity	6.3%	(0.3)%	3.0%

Earnings by Major Operating Area

<i>Millions of dollars</i>	2017	2016	2015
Upstream			
United States	\$ 3,640	\$ (2,054)	\$ (4,055)
International	4,510	(483)	2,094
Total Upstream	8,150	(2,537)	(1,961)
Downstream			
United States	2,938	1,307	3,182
International	2,276	2,128	4,419
Total Downstream	5,214	3,435	7,601
All Other	(4,169)	(1,395)	(1,053)
Net Income (Loss) Attributable to Chevron Corporation^{1,2}	\$ 9,195	\$ (497)	\$ 4,587
	\$ (446)	\$ 58	\$ 769

¹ Includes foreign currency effects:

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 16 for a discussion of financial results by major operating area for the three years ended December 31, 2017.

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, Democratic Republic of the Congo, Denmark, Indonesia, Kazakhstan, Myanmar, Nigeria, the Partitioned Zone between Saudi Arabia and Kuwait, the Philippines, Republic of Congo, Singapore, South Africa, 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 biggest factor affecting the results of operations for the upstream segment is the price of crude oil. The price of crude oil has fallen significantly since mid-year 2014. The downturn in the price of crude oil has impacted the company's results of operations, cash flows, leverage, capital and exploratory investment program and production outlook. A sustained lower price environment could result in the impairment or write-off of specific assets in future periods. The company has responded with reductions in operating expenses, pacing and re-focusing of capital and exploratory expenditures, and increased asset sales. The company anticipates that crude oil prices will increase in the future, as continued growth in demand and a slowing in supply growth should bring global markets into balance; however, the timing of any such increase is unknown. 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 shareholder value in any business environment.

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 18 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 11 and to “Risk Factors” in Part I, Item 1A, on pages 19 through 22 of the company's Annual Report on Form 10-K 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. The company's asset sale program for 2016 and 2017 targeted before-tax proceeds of \$5-10 billion. Proceeds and deposits related to asset sales were \$2.8 billion in 2016 and \$5.2 billion in 2017. Refer to the "Results of Operations" section beginning on page 16 for discussions of net gains on asset sales during 2017. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

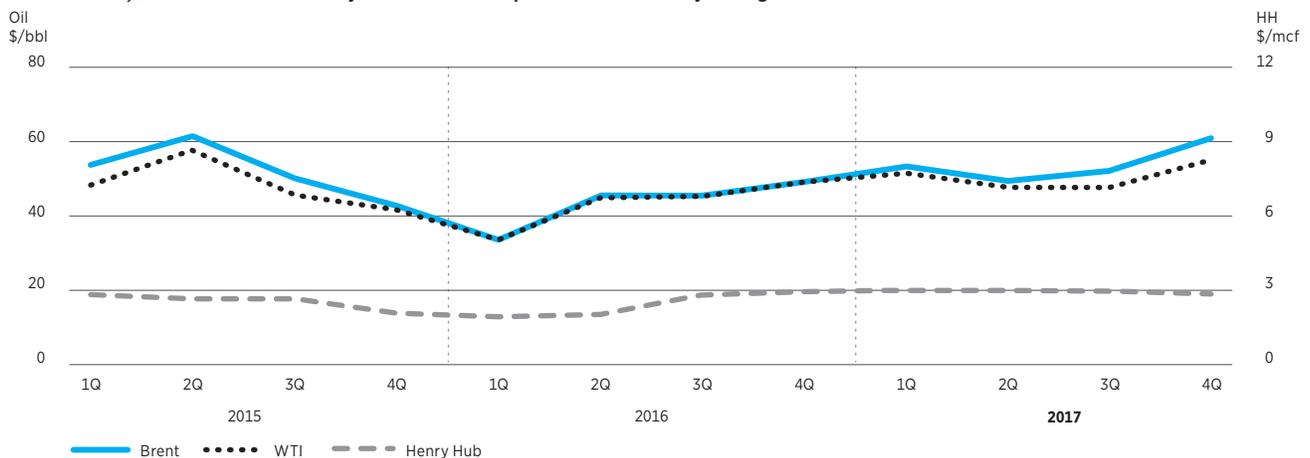
The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of movements in prices for crude oil and natural gas. Management takes these developments into account in the conduct of daily operations and for 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 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, 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. Industry cost inflation in most onshore segments, including North America unconventional, started to modestly rise in 2017 with increases in commodity prices and higher levels of activity and investment. Offshore costs continue to decline driven by lower offshore activity levels and increased competition among suppliers. 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.

WTI Crude Oil, Brent Crude Oil and Henry Hub Natural Gas Spot Prices — Quarterly Average



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 Brent price averaged \$54 per barrel for the full-year 2017, compared to \$44 in 2016. As of mid-February 2018, the Brent price was \$62 per barrel. The majority of the company's equity crude production is priced based on the Brent benchmark. Crude oil prices were better supported in 2017 amid firming demand, rising geopolitical tensions, and ongoing output reductions by OPEC and certain non-OPEC producers. However, upside was limited as rebounding U.S. and other non-OPEC production resulted in ongoing oversupplied conditions. Prices weakened gradually over the first half of 2017 due to concerns that OPEC cuts would be allowed to expire in June 2017, but firmed over the

second half of 2017 after OPEC's decision on May 25, 2017, to extend cuts through the first quarter of 2018. Price support was reinforced on November 30, 2017, when OPEC and their non-OPEC partners agreed to further extend output cuts through December 2018.

The WTI price averaged \$51 per barrel for the full-year 2017, compared to \$43 in 2016. As of mid-February 2018, the WTI price was \$59 per barrel. WTI traded at a discount to Brent throughout 2017. After starting 2017 at a \$2 discount to Brent, the WTI discount expanded to about \$6 by year-end due to rising U.S. crude production, rebounding inventories, and growing concerns that pipeline infrastructure constraints would again restrict flows to export outlets on the Gulf Coast.

A differential in crude oil prices exists between high-gravity, low-sulfur crudes and low-gravity, high-sulfur crudes. The amount of the differential in any period is associated with the relative supply/demand balances for each crude type. In second-half 2017, the differential held generally steady in North America as robust refinery demand supported heavy crude values, while light sweet crude prices in the U.S. were supported by rising exports of domestic production. Outside of North America, differentials were steady to modestly wider amid well-supplied light sweet crude markets in the Atlantic Basin, while rising U.S. exports to Asia increased competitive pressure on Middle East exports to the region. Chevron has producing interests in 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 21 for the company's average U.S. and international crude oil realizations.)

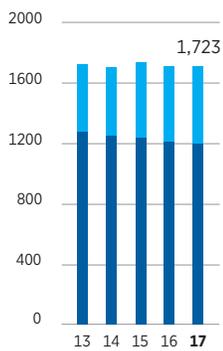
In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged \$2.97 per thousand cubic feet (MCF) during 2017, compared with \$2.46 during 2016. As of mid-February 2018, the Henry Hub spot price was \$2.57 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 most 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 \$4.62 per MCF during 2017, compared with \$4.02 per MCF during 2016. (See page 21 for the company's average natural gas realizations for the U.S. and international regions.)

The company's worldwide net oil-equivalent production in 2017 averaged 2.728 million barrels per day. About one-sixth of the company's net oil-equivalent production in 2017 occurred in the OPEC-member countries of Angola, Nigeria and Venezuela. OPEC quotas had no effect on the company's net crude oil production in 2017 or 2016.

The company estimates that net oil-equivalent production in 2018 will grow 4 to 7 percent compared to 2017, assuming a Brent crude oil price of \$60 per barrel and excluding the impact of anticipated 2018 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, 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; greater-than-expected declines in production from mature fields; or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and, for new, large-scale projects, the time lag between initial exploration and the beginning of production. Investments in upstream projects generally begin well in advance of the start of the associated crude oil and natural gas production.

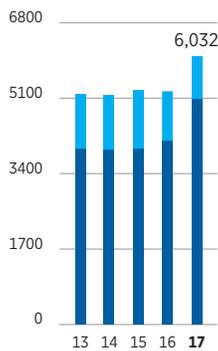
Net liquids production*
Thousands of barrels per day



■ United States
■ International

* Includes equity in affiliates.

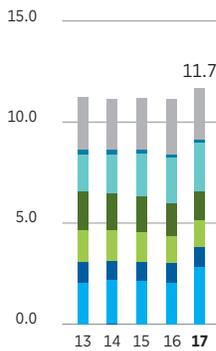
Net natural gas production*
Millions of cubic feet per day



■ United States
■ International

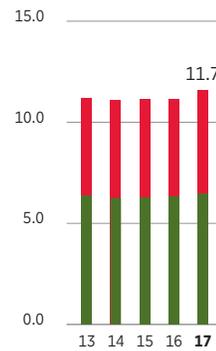
* Includes equity in affiliates.

Net proved reserves
Billions of BOE



■ Affiliates
■ Europe
■ Australia/Oceania
■ Asia
■ Africa
■ Other Americas
■ United States

Net proved reserves liquids & natural gas
Billions of BOE



■ Natural gas
■ Liquids

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 2018, 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 2017 were not significant and are not expected to be significant in 2018.

Net proved reserves for consolidated companies and affiliated companies totaled 11.7 billion barrels of oil-equivalent at year-end 2017, an increase of 5 percent from year-end 2016. The reserve replacement ratio in 2017 was 155 percent. Refer to Table V beginning on page 78 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2015 and each year-end from 2015 through 2017, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2017.

Refer to the "Results of Operations" section on pages 16 through 19 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.

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

Refer to the "Results of Operations" section on pages 16 through 19 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 2017 and early 2018 included the following:

Upstream

Angola Commenced production from the main production facility of the Mafumeira Sul Project.

Australia Achieved start-up of Train 3 at the Gorgon LNG Project and Train 1 at the Wheatstone LNG Project.

Canada Achieved start-up of the Hebron Project.

Indonesia Completed the sale of the geothermal business.

United States Announced significant crude oil discoveries at the Whale and Ballymore prospects in the Gulf of Mexico.

Downstream

Canada Completed the sale of refining and marketing assets in British Columbia and Alberta.

United States The company's 50 percent-owned affiliate, Chevron Phillips Chemical Company LLC achieved start-up of two polyethylene units and reached mechanical completion of a new ethane cracker at its U.S. Gulf Coast Petrochemicals Project in Texas.

Other

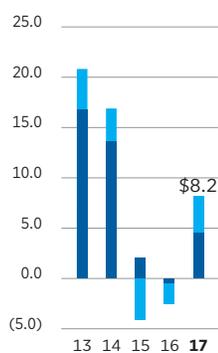
Common Stock Dividends The 2017 annual dividend was \$4.32 per share, making 2017 the 30th consecutive year that the company increased its annual dividend payout. In January 2018, the company's Board of Directors approved a \$0.04 per share increase in the quarterly dividend to \$1.12 per share, payable in March 2018.

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 15, beginning on page 49, 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 12 through 15.

Worldwide Upstream earnings

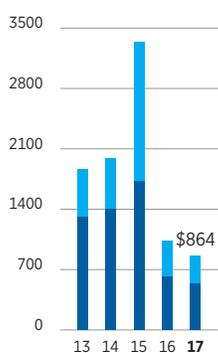
Billions of dollars



■ United States
■ International

Exploration expenses

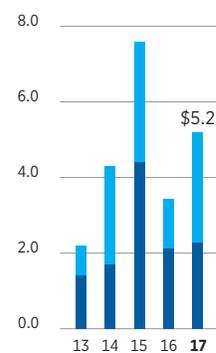
Millions of dollars (before-tax)



■ United States
■ International

Worldwide Downstream earnings

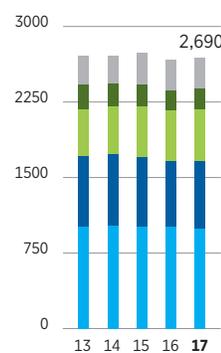
Billions of dollars



■ United States
■ International

Worldwide refined product sales

Thousands of barrels per day



■ Other
■ Fuel oil
■ Jet fuel
■ Diesel/Gas oil
■ Gasoline

U.S. Upstream

Millions of dollars

	2017	2016	2015
Earnings	\$ 3,640	\$ (2,054)	\$ (4,055)

U.S. upstream earnings were \$3.64 billion in 2017, compared with a loss of \$2.05 billion in 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.

U.S. upstream operations incurred a loss of \$2.05 billion in 2016, compared with a loss of \$4.06 billion from 2015. The improvement was due to lower depreciation expense of \$1.2 billion and lower exploration expense of \$780 million primarily reflecting a decrease in impairments and project cancellations. Also contributing to the improvement were lower operating expenses of \$600 million and lower tax items of \$190 million. Partially offsetting these effects were lower crude oil and natural gas realizations of \$920 million.

The company's average realization for U.S. crude oil and natural gas liquids in 2017 was \$44.53 per barrel, compared with \$35.00 in 2016 and \$42.70 in 2015. The average natural gas realization was \$2.10 per thousand cubic feet in 2017, compared with \$1.59 in 2016 and \$1.92 in 2015.

Net oil-equivalent production in 2017 averaged 681,000 barrels per day, down 1 percent from 2016 and down 5 percent from 2015. 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. Between 2016 and 2015, production increases from shale and tight properties in the Permian Basin in Texas and New Mexico, and base business were more than offset by the effect of asset sales and normal field declines.

The net liquids component of oil-equivalent production for 2017 averaged 519,000 barrels per day, up 3 percent from 2016 and 4 percent from 2015. Net natural gas production averaged about 970 million cubic feet per day in 2017, down 13 percent from 2016 and 26 percent from 2015, primarily as a result of asset sales. Refer to the "Selected Operating Data" table on page 21 for a three-year comparison of production volumes in the United States.

International Upstream

<i>Millions of dollars</i>	2017	2016	2015
Earnings*	\$ 4,510	\$ (483)	\$ 2,094
*Includes foreign currency effects:	\$ (456)	\$ 122	\$ 725

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.

International upstream incurred a loss of \$483 million in 2016, compared with earnings of \$2.09 billion in 2015. The decrease in earnings was primarily due to lower crude oil realizations of \$1.89 billion, lower natural gas realizations of \$600 million, lower gains on asset sales of \$450 million and higher tax items of \$330 million. Partially offsetting the decrease were lower exploration and operating expenses of \$640 million and \$520 million, respectively, and higher natural gas sales volumes of \$330 million. Foreign currency effects had an unfavorable impact on earnings of \$603 million between periods.

The company's average realization for international crude oil and natural gas liquids in 2017 was \$49.46 per barrel, compared with \$38.61 in 2016 and \$46.52 in 2015. The average natural gas realization was \$4.62 per thousand cubic feet in 2017, compared with \$4.02 and \$4.53 in 2016 and 2015, respectively.

International net oil-equivalent production was 2.05 million barrels per day in 2017, up 8 percent from 2016 and 2015. 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. Between 2016 and 2015, production increases from major capital projects, base business, and shale and tight properties were largely offset by normal field declines, the Partitioned Zone shut-in, the impact of civil unrest in Nigeria and planned turnaround activity.

The net liquids component of international oil-equivalent production was 1.20 million barrels per day in 2017, down 1 percent from 2016 and down 3 percent from 2015. International net natural gas production of 5.1 billion cubic feet per day in 2017 was up 23 percent from 2016 and 28 percent from 2015.

Refer to the "Selected Operating Data" table, on page 21, for a three-year comparison of international production volumes.

U.S. Downstream

Millions of dollars	2017	2016	2015
Earnings	\$ 2,938	\$ 1,307	\$ 3,182

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 Chevron Phillips Chemicals Company LLC of \$70 million, primarily reflecting the impacts from Hurricane Harvey.

U.S. downstream operations earned \$1.31 billion in 2016, compared with \$3.18 billion in 2015. The decrease was due to lower margins on refined product sales of \$1.45 billion, lower earnings from the 50 percent-owned Chevron Phillips Chemicals Company LLC of \$400 million and an asset impairment of \$110 million. Partially offsetting this decrease were lower operating expenses of \$80 million and higher gains on asset sales of \$110 million.

Refined product sales of 1.20 million barrels per day in 2017 were down 1 percent, primarily due to divestment of Hawaii refining and marketing assets in fourth quarter 2016. Sales volumes of refined products were 1.21 million barrels per day in 2016, a decrease of 1 percent from 2015, mainly reflecting lower sales of diesel. U.S. branded gasoline sales of 528,000 barrels per day in 2017 decreased 1 percent from 2016 and increased 1 percent from 2015.

Refer to the "Selected Operating Data" table on page 21 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

Millions of dollars	2017	2016	2015
Earnings*	\$ 2,276	\$ 2,128	\$ 4,419
*Includes foreign currency effects:	\$ (90)	\$ (25)	\$ 47

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.

International downstream earned \$2.13 billion in 2016, compared with \$4.42 billion in 2015. The decrease in earnings was primarily due to the absence of a \$1.6 billion gain from the sale of the company's interest in Caltex Australia Limited in 2015, partially offset by 2016 asset sales gains of \$420 million. Lower margins on refined product sales of \$1.14 billion also contributed to the decline. Partially offsetting these decreases were lower operating expenses of \$240 million. Foreign currency effects had an unfavorable impact on earnings of \$72 million between periods.

Total refined product 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. Sales of 1.46 million barrels per day in 2016 were down 3 percent from 2015. Excluding the effects of the Caltex Australia Limited divestment, refined product sales were down 1 percent, primarily reflecting lower fuel oil sales.

Refer to the "Selected Operating Data" table, on page 21, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars	2017	2016	2015
Net charges*	\$ (4,169)	\$ (1,395)	\$ (1,053)
*Includes foreign currency effects:	\$ 100	\$ (39)	\$ (3)

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 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. Net

charges in 2016 increased \$342 million from 2015, mainly due to higher corporate charges, interest expense and corporate tax items, partially offset by lower environmental reserve additions and lower charges related to reductions in corporate staffs.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

<i>Millions of dollars</i>	2017	2016	2015
Sales and other operating revenues	\$ 134,674	\$ 110,215	\$ 129,925

Sales and other operating revenues increased in 2017 mainly due to higher refined product and crude oil prices, higher crude oil volumes, and higher natural gas volumes. The decrease between 2016 and 2015 was primarily due to lower refined product and crude oil prices, partially offset by higher crude oil volumes.

<i>Millions of dollars</i>	2017	2016	2015
Income from equity affiliates	\$ 4,438	\$ 2,661	\$ 4,684

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

Income from equity affiliates decreased in 2016 from 2015 primarily due to lower upstream-related earnings from Tengizchevroil in Kazakhstan and Petroboscan in Venezuela, and lower downstream-related earnings from CPChem and GS Caltex in South Korea.

Refer to Note 16, beginning on page 52, for a discussion of Chevron's investments in affiliated companies.

<i>Millions of dollars</i>	2017	2016	2015
Other income	\$ 2,610	\$ 1,596	\$ 3,868

Other income of \$2.6 billion in 2017 included net gains from asset sales of \$2.2 billion before-tax. Other income in 2016 and 2015 included net gains from asset sales of \$1.1 billion and \$3.2 billion before-tax, respectively. Interest income was approximately \$107 million in 2017, \$145 million in 2016 and \$119 million in 2015. Foreign currency effects decreased other income by \$131 million in 2017, and \$186 million in 2016 and increased other income \$82 million in 2015.

<i>Millions of dollars</i>	2017	2016	2015
Purchased crude oil and products	\$ 75,765	\$ 59,321	\$ 69,751

Crude oil and product 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. The decrease between 2016 and 2015 of \$10.4 billion was primarily due to lower crude oil and refined product prices, partially offset by an increase in crude oil volumes.

<i>Millions of dollars</i>	2017	2016	2015
Operating, selling, general and administrative expenses	\$ 23,885	\$ 24,952	\$ 27,477

Operating, selling, general and administrative expenses decreased \$1.1 billion between 2017 and 2016. The decrease included lower employee expenses of \$690 million and non-operated joint venture expenses of \$380 million.

Operating, selling, general and administrative expenses decreased \$2.5 billion between 2016 and 2015. The decrease included lower employee expenses of \$800 million, transportation expenses of \$680 million, contract labor expenses of \$370 million, materials and supplies expenses of \$310 million, and fuel expenses of \$310 million.

<i>Millions of dollars</i>	2017	2016	2015
Exploration expense	\$ 864	\$ 1,033	\$ 3,340

Exploration expenses in 2017 decreased from 2016 primarily due to lower charges for well write-offs.

Exploration expenses in 2016 decreased from 2015 primarily due to significantly higher 2015 charges for well write-offs largely related to project cancellations, and lower 2016 geological and geophysical expenses.

<i>Millions of dollars</i>	2017	2016	2015
Depreciation, depletion and amortization	\$ 19,349	\$ 19,457	\$ 21,037

Depreciation, depletion and amortization expenses decreased in 2017 from 2016 mainly 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.

The decrease in 2016 from 2015 was primarily due to lower impairments of certain oil and gas producing fields of about \$3.0 billion in 2016 compared with about \$3.5 billion in 2015. Also contributing to the decrease were lower production levels and accretion expenses for certain oil and gas producing fields.

<i>Millions of dollars</i>	2017	2016	2015
Taxes other than on income	\$ 12,331	\$ 11,668	\$ 12,030

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. Taxes other than on income decreased in 2016 from 2015 primarily due to lower refined product and crude oil prices, and the divestment of the Pakistan fuels business at the end of June 2015.

<i>Millions of dollars</i>	2017	2016	2015
Income tax (benefit) expense	\$ (48)	\$ (1,729)	\$ 132

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 18 on page 57.

The decline in income tax expense in 2016 of \$1.86 billion is consistent with the decline in total income before tax for the company of \$7.00 billion. U.S. losses before tax increased from a loss of \$2.88 billion in 2015 to a loss of \$4.32 billion in 2016. This \$1.44 billion increase in losses was primarily driven by the effect of lower crude oil prices. The increase in losses had a direct impact on the company's U.S. income tax benefit, resulting in an increase of \$624 million between year-over-year periods, from a tax benefit of \$1.69 billion in 2015 to a tax benefit of \$2.32 billion in 2016. International income before tax was reduced between calendar years from \$7.72 billion in 2015 to \$2.16 billion in 2016. This \$5.56 billion decline was also primarily driven by the effect of lower crude oil prices. This effect drove the \$1.24 billion reduction in international income tax expense between year-over-year periods, from \$1.83 billion in 2015 to \$588 million in 2016. Refer also to the discussion of the effective income tax rate in Note 18 on page 57.

Selected Operating Data^{1,2}

	2017	2016	2015
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	519	504	501
Net Natural Gas Production (MMCFPD) ³	970	1,120	1,310
Net Oil-Equivalent Production (MBOEPD)	681	691	720
Sales of Natural Gas (MMCFPD)	3,331	3,317	3,913
Sales of Natural Gas Liquids (MBPD)	30	30	26
Revenues from Net Production			
Liquids (\$/Bbl)	\$ 44.53	\$ 35.00	\$ 42.70
Natural Gas (\$/MCF)	\$ 2.10	\$ 1.59	\$ 1.92
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD) ⁴	1,204	1,215	1,243
Net Natural Gas Production (MMCFPD) ³	5,062	4,132	3,959
Net Oil-Equivalent Production (MBOEPD) ⁴	2,047	1,903	1,902
Sales of Natural Gas (MMCFPD)	5,081	4,491	4,299
Sales of Natural Gas Liquids (MBPD)	29	24	24
Revenues from Liftings			
Liquids (\$/Bbl)	\$ 49.46	\$ 38.61	\$ 46.52
Natural Gas (\$/MCF)	\$ 4.62	\$ 4.02	\$ 4.53
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD) ⁴			
United States	681	691	720
International	2,047	1,903	1,902
Total	2,728	2,594	2,622
U.S. Downstream			
Gasoline Sales (MBPD) ⁵	625	631	621
Other Refined Product Sales (MBPD)	572	582	607
Total Refined Product Sales (MBPD)	1,197	1,213	1,228
Sales of Natural Gas Liquids (MBPD)	109	115	127
Refinery Input (MBPD) ⁶	901	900	924
International Downstream			
Gasoline Sales (MBPD) ⁵	365	382	389
Other Refined Product Sales (MBPD)	1,128	1,080	1,118
Total Refined Product Sales (MBPD) ⁷	1,493	1,462	1,507
Sales of Natural Gas Liquids (MBPD)	64	61	65
Refinery Input (MBPD) ⁸	760	788	778

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	37	54	66
International	528	432	430

⁴ Includes net production of synthetic oil:

Canada	51	50	47
Venezuela affiliate	28	28	29

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):

366	377	420
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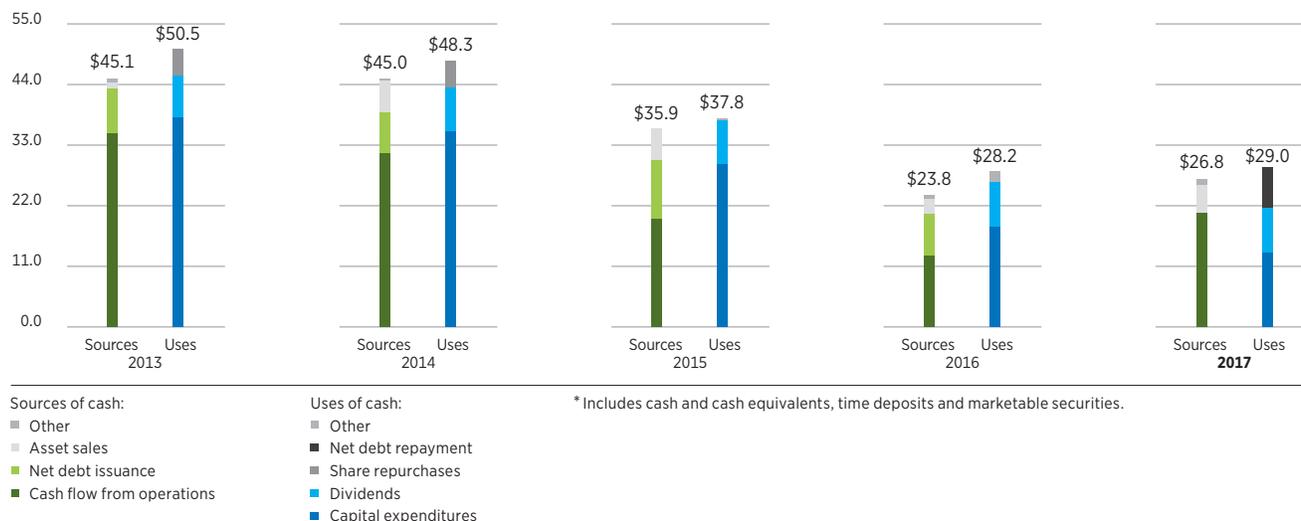
⁸ In 2017, the company sold the Burnaby Refinery in British Columbia, Canada, which had operable capacity of 55,000 barrels per day. In 2015, the company sold its interests in affiliates in Australia and New Zealand, which included operable refinery capacities of 55,000 and 12,000 barrels per day, respectively.

Liquidity and Capital Resources

Sources and uses of cash

Sources and uses of cash*

Billions of dollars



Cash flow from operations increased \$7.7 billion in 2017 primarily due to higher crude oil prices. The company also continued to reduce cash outlays and increase asset sales. Progress on these actions during 2017 included:

- Reducing cash capital expenditures to \$13.4 billion, a 26 percent decrease compared to 2016,
- Reducing operating and administrative expenses by \$1.1 billion, a 4 percent decrease compared to 2016, and
- Realizing net proceeds from asset sales of \$5.2 billion during 2017.

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 and Marketable Securities Total balances were \$4.8 billion and \$7.0 billion at December 31, 2017 and 2016, respectively. Cash provided by operating activities in 2017 was \$20.5 billion, compared with \$12.8 billion in 2016 and \$19.5 billion in 2015, reflecting higher crude oil prices. Cash provided by operating activities was net of contributions to employee pension plans of approximately \$1.0 billion in 2017 and \$0.9 billion in both 2016 and 2015. Cash provided by investing activities included proceeds and deposits related to asset sales of \$5.2 billion in 2017, \$2.8 billion in 2016, and \$5.7 billion in 2015.

Restricted cash of \$1.1 billion and \$1.4 billion at December 31, 2017 and 2016, respectively, was held in cash and short-term marketable securities and recorded as "Deferred charges and other 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.

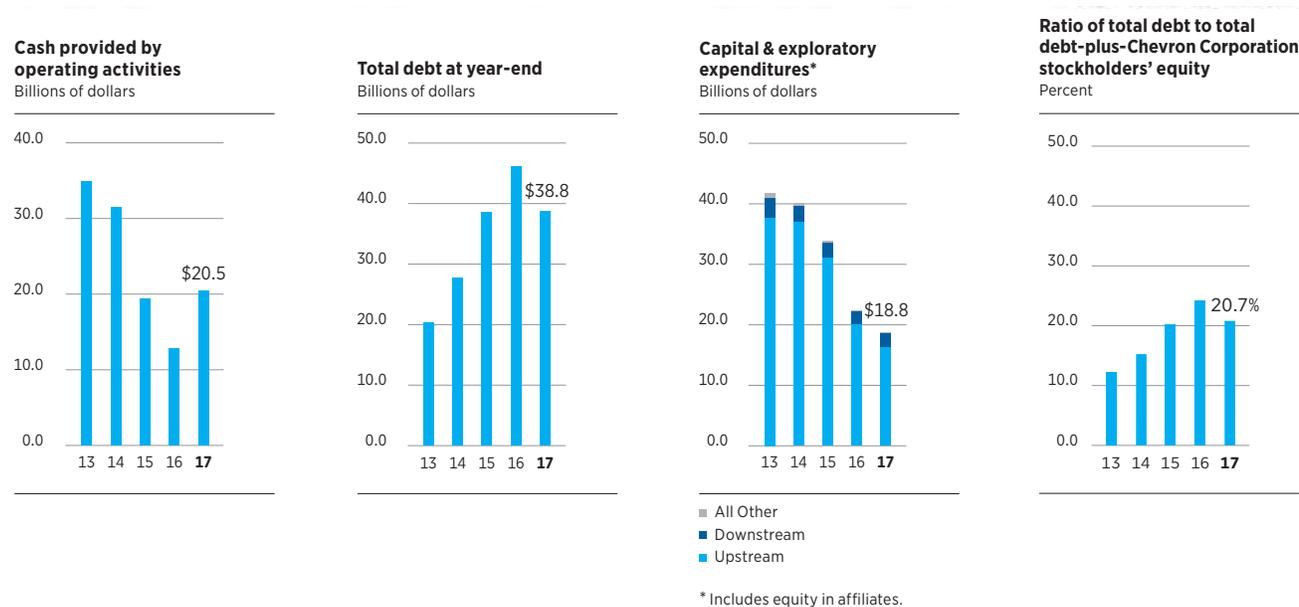
Dividends Dividends paid to common stockholders were \$8.1 billion in 2017, \$8.0 billion in 2016 and \$8.0 billion in 2015.

Debt and Capital Lease Obligations Total debt and capital lease obligations were \$38.8 billion at December 31, 2017, down from \$46.1 billion at year-end 2016.

The \$7.3 billion decrease in total debt and capital lease obligations during 2017 was primarily due to a decrease in short-term obligations reflecting higher crude oil prices. The company completed a bond issuance of \$4.0 billion in first quarter 2017 and repaid long-term notes totaling \$6.2 billion that matured in February, November and December 2017. 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 \$15.2 billion at December 31, 2017, compared with \$19.8 billion at year-end 2016. Of these amounts, \$10.0 billion and \$9.0 billion were reclassified to long-term debt at the end of 2017 and 2016, respectively.

At year-end 2017, settlement of these obligations was not expected to require the use of working capital in 2018, 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 August 2018 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.



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, the capital program and cash that may be generated from asset dispositions. 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 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 19, Short-Term Debt, on page 60.

Common Stock Repurchase Program In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits. The company did not acquire any shares under the program in 2017 or 2016. From the inception of the program through 2014, the company had purchased 180.9 million shares for \$20.0 billion.

Capital and Exploratory Expenditures

Capital and exploratory expenditures by business segment for 2017, 2016 and 2015 are as follows:

Millions of dollars	2017			2016			2015		
	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream	\$ 5,145	\$ 11,243	\$ 16,388	\$ 4,713	\$ 15,403	\$ 20,116	\$ 7,582	\$ 23,535	\$ 31,117
Downstream	1,656	534	2,190	1,545	527	2,072	1,923	513	2,436
All Other	239	4	243	235	5	240	418	8	426
Total	\$ 7,040	\$ 11,781	\$ 18,821	\$ 6,493	\$ 15,935	\$ 22,428	\$ 9,923	\$ 24,056	\$ 33,979
Total, Excluding Equity in Affiliates	\$ 6,295	\$ 7,783	\$ 14,078	\$ 5,456	\$ 13,202	\$ 18,658	\$ 8,579	\$ 22,003	\$ 30,582

Total expenditures for 2017 were \$18.8 billion, including \$4.7 billion for the company's share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2016 and 2015, expenditures were \$22.4 billion and \$34.0 billion, respectively, including the company's share of affiliates' expenditures of \$3.8 billion and \$3.4 billion, respectively.

Of the \$18.8 billion of expenditures in 2017, 87 percent, or \$16.4 billion, related to upstream activities. Approximately 90 percent was expended for upstream operations in 2016 and 92 percent in 2015. International upstream accounted for 69 percent of the worldwide upstream investment in 2017, 77 percent in 2016 and 76 percent in 2015.

The company estimates that 2018 capital and exploratory expenditures will be \$18.3 billion, including \$5.5 billion of spending by affiliates. This planned reduction, compared to 2017 expenditures, reflects project completions, improved efficiencies, and investment high-grading, including the full funding of the company's advantaged Permian Basin position. Approximately 86 percent of the total, or \$15.8 billion, is budgeted for exploration and production activities. Approximately \$8.7 billion of planned upstream capital spending relates to base producing assets, including \$3.3 billion for the Permian and \$1.0 billion for other shale and tight rock investments. Approximately \$5.5 billion of the upstream program is planned for major capital projects underway, including \$3.7 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 \$1.1 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 2018 is estimated to be \$2.2 billion, with \$1.4 billion estimated for projects in the United States.

Investments in technology companies and other corporate businesses in 2018 are budgeted at \$0.3 billion.

Noncontrolling Interests The company had noncontrolling interests of \$1.2 billion at December 31, 2017 and December 31, 2016. Distributions to noncontrolling interests totaled \$78 million and \$63 million in 2017 and 2016, respectively.

Pension Obligations Information related to pension plan contributions is included on page 68 in Note 23, Employee Benefit Plans, under the heading "Cash Contributions and Benefit Payments."

Financial Ratios

	At December 31		
	2017	2016	2015
Current Ratio	1.0	0.9	1.3
Interest Coverage Ratio	10.7	(2.6)	9.9
Debt Ratio	20.7 %	24.1 %	20.2 %

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 2017, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately \$3.9 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 2017 was higher than 2016 and 2015 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 20.7 percent at year-end 2017, compared with 24.1 percent and 20.2 percent at year-end 2016 and 2015, 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

The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2018 – \$1.4 billion; 2019 – \$1.4 billion;

2020 – \$1.0 billion; 2021 – \$0.9 billion; 2022 – \$0.5 billion; 2023 and after – \$2.6 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$1.3 billion in 2017, \$1.3 billion in 2016 and \$1.9 billion in 2015.

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

<i>Millions of dollars</i>	Payments Due by Period				
	Total ¹	2018	2019-2020	2021-2022	After 2022
On Balance Sheet: ²					
Short-Term Debt ³	\$ 5,194	\$ 5,194	\$ —	\$ —	\$ —
Long-Term Debt ³	33,512	—	20,054	6,104	7,354
Noncancelable Capital Lease Obligations	226	26	35	23	142
Interest	4,078	786	1,173	850	1,269
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,895	693	1,102	562	538
Throughput and Take-or-Pay Agreements ⁴	5,277	655	1,285	866	2,471
Other Unconditional Purchase Obligations ⁴	2,560	747	1,109	609	95

¹ Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 23 beginning on page 64.

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 \$10.0 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 2019–2020 period. The amounts represent only the principal balance.

⁴ 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.

Direct Guarantees

<i>Millions of dollars</i>	Commitment Expiration by Period				
	Total	2018	2019-2020	2021-2022	After 2022
Guarantee of nonconsolidated affiliate or joint-venture obligations	\$ 1,082	\$ 114	\$ 577	\$ 214	\$ 177

The company has two guarantees of equity affiliates totaling \$1.08 billion. Of this amount, \$712 million is associated with a financing arrangement with an equity affiliate. Over the approximate 4-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of \$370 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 10-year remaining term of this guarantee, the maximum guarantee amount will be reduced as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of amounts paid under the guarantee. Chevron has recorded no liability for either guarantee.

Indemnifications Information related to indemnifications is included on page 70 in Note 25, Other Contingencies and Commitments, under the heading "Indemnifications."

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, of the company's 2017 Annual Report on Form 10-K.

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 2017.

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 2017 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 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, 2017 and 2016 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, 2017.

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 2017, 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 53, in Note 16, 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 53 in Note 17 under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 17 under the heading "Ecuador," beginning on page 53.

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.

<i>Millions of dollars</i>	2017	2016	2015
Balance at January 1	\$ 1,467	\$ 1,578	\$ 1,683
Net Additions	323	260	365
Expenditures	(361)	(371)	(470)
Balance at December 31	\$ 1,429	\$ 1,467	\$ 1,578

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 \$14.2 billion for asset retirement obligations at year-end 2017 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 2017 environmental expenditures. Refer to Note 25 on page 70 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 26 on page 71 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 21, Accounting for Suspended Exploratory Wells, beginning on page 62.

Income Taxes Information related to income tax contingencies is included on pages 57 through 60 in Note 18 and page 69 in Note 25 under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page 71 in Note 25 to the Consolidated Financial Statements under the heading "Other Contingencies."

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 19 through 22 of the company's Annual Report on Form 10-K 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 2017 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 2018, 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:

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 2017, 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 2017 were 6.2 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 2017 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 78, for the changes in proved reserve estimates for the three years ended December 31, 2017, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 84 for estimates of proved reserve values for each of the three years ended December 31, 2017.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1, beginning on page 39, 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 24 on page 69 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page 39.

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 of. 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 the year 2017. The company reported impairments for certain oil and gas properties during 2016 due to reservoir performance and lower crude oil prices. The company reported impairments for certain oil and gas properties during 2015 primarily as a result of downward revisions in the company's longer-term crude oil price outlook. The impairments for the years 2016 and 2015 were primarily in Brazil and the United States. 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 2017 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 26 on page 71 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 23, beginning on page 64, 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 66 in Note 23 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

For 2017, the company used an expected long-term rate of return of 6.75 percent and a discount rate for service costs of 4.2 percent and a discount rate for interest cost of 3.0 percent for U.S. pension plans. The actual return for 2017 was 15.7 percent. For the 10 years ending December 31, 2017, actual asset returns averaged 5.2 percent for the plan. Additionally, with the exception of three years within this 10-year period, actual asset returns for this plan equaled or exceeded 6.75 percent during each year.

Total pension expense for 2017 was \$1.2 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 61 percent of companywide pension expense, would have reduced total pension plan expense for 2017

by approximately \$79 million. A 1 percent increase in the discount rates for this same plan would have reduced pension expense for 2017 by approximately \$305 million.

The aggregate funded status recognized at December 31, 2017, was a net liability of approximately \$4.4 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At December 31, 2017, the company used a discount rate of 3.5 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 \$478 million, and would have decreased the plan's underfunded status from approximately \$2.0 billion to \$1.5 billion.

For the company's OPEB plans, expense for 2017 was \$94 million, and the total liability, all unfunded at the end of 2017, was \$2.8 billion. For the main U.S. OPEB plan, the company used a discount rate for service cost of 4.6 percent and a discount rate for interest cost of 3.4 percent to measure expense in 2017, and a 3.6 percent discount rate to measure the benefit obligations at December 31, 2017. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2017 OPEB expense and OPEB liabilities at the end of 2017. For information on the sensitivity of the health care cost-trend rate, refer to page 66 in Note 23 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 66 in Note 23 for a description of the method used to amortize the \$5.5 billion of before-tax actuarial losses recorded by the company as of December 31, 2017, and an estimate of the costs to be recognized in expense during 2018. In addition, information related to company contributions is included on page 68 in Note 23 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 25 beginning on page 69. 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, 2017.

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 5 beginning on page 43 for information regarding new accounting standards.

Quarterly Results and Stock Market Data

Unaudited

Millions of dollars, except per-share amounts	2017				2016			
	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	\$36,381	\$33,892	\$32,877	\$31,524	\$30,142	\$29,159	\$27,844	\$23,070
Income from equity affiliates	936	1,036	1,316	1,150	778	555	752	576
Other income	299	1,277	287	747	577	426	686	(93)
Total Revenues and Other Income	37,616	36,205	34,480	33,421	31,497	30,140	29,282	23,553
Costs and Other Deductions								
Purchased crude oil and products	21,158	18,776	18,325	17,506	16,976	15,842	15,278	11,225
Operating expenses	5,182	4,937	4,662	4,656	5,144	4,666	5,054	5,404
Selling, general and administrative expenses	1,349	1,238	991	870	1,544	1,109	1,033	998
Exploration expenses	356	239	125	144	191	258	214	370
Depreciation, depletion and amortization	4,735	5,109	5,311	4,194	4,203	4,130	6,721	4,403
Taxes other than on income ¹	3,182	3,213	3,065	2,871	2,869	2,962	2,973	2,864
Interest and debt expense	173	35	48	51	58	64	79	—
Total Costs and Other Deductions	36,135	33,547	32,527	30,292	30,985	29,031	31,352	25,264
Income (Loss) Before Income Tax Expense	1,481	2,658	1,953	3,129	512	1,109	(2,070)	(1,711)
Income Tax Expense (Benefit)	(1,637)	672	487	430	74	(192)	(607)	(1,004)
Net Income (Loss)	\$ 3,118	\$ 1,986	\$ 1,466	\$ 2,699	\$ 438	\$ 1,301	\$ (1,463)	\$ (707)
Less: Net income attributable to noncontrolling interests	7	34	16	17	23	18	7	18
Net Income (Loss) Attributable to Chevron Corporation	\$ 3,111	\$ 1,952	\$ 1,450	\$ 2,682	\$ 415	\$ 1,283	\$ (1,470)	\$ (725)
Per Share of Common Stock								
Net Income (Loss) Attributable to Chevron Corporation								
– Basic	\$ 1.65	\$ 1.03	\$ 0.77	\$ 1.43	\$ 0.22	\$ 0.68	\$ (0.78)	\$ (0.39)
– Diluted	\$ 1.64	\$ 1.03	\$ 0.77	\$ 1.41	\$ 0.22	\$ 0.68	\$ (0.78)	\$ (0.39)
Dividends	\$ 1.08	\$ 1.07	\$ 1.07	\$ 1.07				
Common Stock Price Range – High²	\$126.20	\$118.33	\$110.67	\$119.00	\$119.00	\$107.58	\$105.00	\$ 97.91
– Low ²	\$112.57	\$102.55	\$102.55	\$105.85	\$ 99.61	\$ 97.53	\$ 92.43	\$ 75.33
¹ Includes excise, value-added and similar taxes:	\$ 1,874	\$ 1,867	\$ 1,771	\$ 1,677	\$ 1,697	\$ 1,772	\$ 1,784	\$ 1,652
² Intraday price.								

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 12, 2018, stockholders of record numbered approximately 131,000. There are no restrictions on the company's ability to pay dividends.

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).

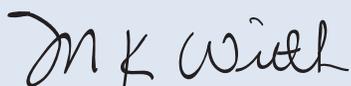
The Board of Directors of Chevron has an Audit Committee composed of directors who are not officers or employees of the company. The Audit Committee meets regularly with members of management, the internal auditors and the independent registered public accounting firm to review accounting, internal control, 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, 2017. 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, 2017.

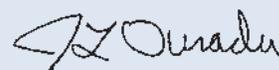
The effectiveness of the company's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.



Michael K. Wirth
Chairman of the Board
and Chief Executive Officer



Patricia E. Yarrington
Vice President
and Chief Financial Officer



Jeanette L. Ourada
Vice President
and Comptroller

February 22, 2018

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 as of December 31, 2017 and 2016, 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, 2017, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company’s internal control over financial reporting as of December 31, 2017, 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, 2017 and 2016 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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, 2017, 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. 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.

PricewaterhouseCoopers LLP

San Francisco, California

February 22, 2018

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		
	2017	2016	2015
Revenues and Other Income			
Sales and other operating revenues*	\$ 134,674	\$ 110,215	\$ 129,925
Income from equity affiliates	4,438	2,661	4,684
Other income	2,610	1,596	3,868
Total Revenues and Other Income	141,722	114,472	138,477
Costs and Other Deductions			
Purchased crude oil and products	75,765	59,321	69,751
Operating expenses	19,437	20,268	23,034
Selling, general and administrative expenses	4,448	4,684	4,443
Exploration expenses	864	1,033	3,340
Depreciation, depletion and amortization	19,349	19,457	21,037
Taxes other than on income*	12,331	11,668	12,030
Interest and debt expense	307	201	—
Total Costs and Other Deductions	132,501	116,632	133,635
Income (Loss) Before Income Tax Expense	9,221	(2,160)	4,842
Income Tax Expense (Benefit)	(48)	(1,729)	132
Net Income (Loss)	9,269	(431)	4,710
Less: Net income attributable to noncontrolling interests	74	66	123
Net Income (Loss) Attributable to Chevron Corporation	\$ 9,195	\$ (497)	\$ 4,587
Per Share of Common Stock			
Net Income (Loss) Attributable to Chevron Corporation			
- Basic	\$ 4.88	\$ (0.27)	\$ 2.46
- Diluted	\$ 4.85	\$ (0.27)	\$ 2.45
* Includes excise, value-added and similar taxes.	\$ 7,189	\$ 6,905	\$ 7,359

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2017	2016	2015
Net Income (Loss)	\$ 9,269	\$ (431)	\$ 4,710
Currency translation adjustment			
Unrealized net change arising during period	57	(22)	(44)
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	(3)	27	(21)
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	817	918	794
Actuarial (loss) gain arising during period	(571)	(315)	109
Prior service credits (cost)			
Amortization to net income of net prior service costs and curtailments	(20)	19	30
Prior service (costs) credits arising during period	(1)	345	6
Defined benefit plans sponsored by equity affiliates - benefit (cost)	19	(19)	30
Income (taxes) benefit on defined benefit plans	(44)	(505)	(336)
Total	200	443	633
Other Comprehensive Gain, Net of Tax	254	448	568
Comprehensive Income	9,523	17	5,278
Comprehensive income attributable to noncontrolling interests	(74)	(66)	(123)
Comprehensive Income (Loss) Attributable to Chevron Corporation	\$ 9,449	\$ (49)	\$ 5,155

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet
Millions of dollars, except per-share amount

	At December 31	
	2017	2016
Assets		
Cash and cash equivalents	\$ 4,813	\$ 6,988
Marketable securities	9	13
Accounts and notes receivable (less allowance: 2017 - \$490; 2016 - \$373)	15,353	14,092
Inventories:		
Crude oil and petroleum products	3,142	2,720
Chemicals	476	455
Materials, supplies and other	1,967	2,244
Total inventories	5,585	5,419
Prepaid expenses and other current assets	2,800	3,107
Total Current Assets	28,560	29,619
Long-term receivables, net	2,849	2,485
Investments and advances	32,497	30,250
Properties, plant and equipment, at cost	344,485	336,077
Less: Accumulated depreciation, depletion and amortization	166,773	153,891
Properties, plant and equipment, net	177,712	182,186
Deferred charges and other assets	7,017	6,838
Goodwill	4,531	4,581
Assets held for sale	640	4,119
Total Assets	\$ 253,806	\$ 260,078
Liabilities and Equity		
Short-term debt (net of unamortized discount and debt issuance costs: \$2 in 2017, \$3 in 2016)	\$ 5,192	\$ 10,840
Accounts payable	14,565	13,986
Accrued liabilities	5,267	4,882
Federal and other taxes on income	1,600	1,050
Other taxes payable	1,113	1,027
Total Current Liabilities	27,737	31,785
Long-term debt (net of unamortized discount and debt issuance costs: \$35 in 2017, \$41 in 2016)	33,477	35,193
Capital lease obligations	94	93
Deferred credits and other noncurrent obligations	21,106	21,553
Noncurrent deferred income taxes	14,652	17,516
Noncurrent employee benefit plans	7,421	7,216
Total Liabilities*	\$ 104,487	\$ 113,356
Preferred stock (authorized 100,000,000 shares; \$1.00 par value; none issued)	—	—
Common stock (authorized 6,000,000,000 shares; \$0.75 par value; 2,442,676,580 shares issued at December 31, 2017 and 2016)	1,832	1,832
Capital in excess of par value	16,848	16,595
Retained earnings	174,106	173,046
Accumulated other comprehensive loss	(3,589)	(3,843)
Deferred compensation and benefit plan trust	(240)	(240)
Treasury stock, at cost (2017 - 537,974,695 shares; 2016 - 551,170,158 shares)	(40,833)	(41,834)
Total Chevron Corporation Stockholders' Equity	148,124	145,556
Noncontrolling interests	1,195	1,166
Total Equity	149,319	146,722
Total Liabilities and Equity	\$ 253,806	\$ 260,078

See accompanying Notes to the Consolidated Financial Statements.

* Refer to Note 25, "Other Contingencies and Commitments" beginning on page 69.

Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2017	2016	2015
Operating Activities			
Net Income (Loss)	\$ 9,269	\$ (431)	\$ 4,710
Adjustments			
Depreciation, depletion and amortization	19,349	19,457	21,037
Dry hole expense	198	489	2,309
Distributions less than income from equity affiliates	(2,214)	(1,227)	(760)
Net before-tax gains on asset retirements and sales	(2,195)	(1,149)	(3,215)
Net foreign currency effects	131	186	(82)
Deferred income tax provision	(3,203)	(3,835)	(1,861)
Net decrease (increase) in operating working capital	476	(550)	(1,979)
Increase in long-term receivables	(368)	(131)	(59)
(Increase) decrease in other deferred charges	(199)	235	25
Cash contributions to employee pension plans	(980)	(870)	(868)
Other	251	672	199
Net Cash Provided by Operating Activities	20,515	12,846	19,456
Investing Activities			
Capital expenditures	(13,404)	(18,109)	(29,504)
Proceeds and deposits related to asset sales	5,247	2,777	5,739
Net maturities of time deposits	—	—	8
Net sales of marketable securities	4	297	122
Net borrowing of loans by equity affiliates	(16)	(2,034)	(217)
Net (purchases) sales of other short-term investments	(32)	217	44
Net Cash Used for Investing Activities	(8,201)	(16,852)	(23,808)
Financing Activities			
Net (repayments) borrowings of short-term obligations	(5,142)	2,130	(335)
Proceeds from issuances of long-term debt	3,991	6,924	11,091
Repayments of long-term debt and other financing obligations	(6,310)	(1,584)	(32)
Cash dividends - common stock	(8,132)	(8,032)	(7,992)
Distributions to noncontrolling interests	(78)	(63)	(128)
Net sales of treasury shares	1,117	650	211
Net Cash (Used for) Provided by Financing Activities	(14,554)	25	2,815
Effect of Exchange Rate Changes on Cash and Cash Equivalents	65	(53)	(226)
Net Change in Cash and Cash Equivalents	(2,175)	(4,034)	(1,763)
Cash and Cash Equivalents at January 1	6,988	11,022	12,785
Cash and Cash Equivalents at December 31	\$ 4,813	\$ 6,988	\$ 11,022

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2017		2016		2015	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred Stock	—	\$ —	—	\$ —	—	\$ —
Common Stock	2,442,677	\$ 1,832	2,442,677	\$ 1,832	2,442,677	\$ 1,832
Capital in Excess of Par						
Balance at January 1		\$ 16,595		\$ 16,330		\$ 16,041
Treasury stock transactions		253		265		289
Balance at December 31		\$ 16,848		\$ 16,595		\$ 16,330
Retained Earnings						
Balance at January 1		\$ 173,046		\$ 181,578		\$ 184,987
Net income (loss) attributable to Chevron Corporation		9,195		(497)		4,587
Cash dividends on common stock		(8,132)		(8,032)		(7,992)
Stock dividends		(3)		(3)		(3)
Tax (charge) benefit from dividends paid on unallocated ESOP shares and other		—		—		(1)
Balance at December 31		\$ 174,106		\$ 173,046		\$ 181,578
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		\$ (162)		\$ (140)		\$ (96)
Change during year		57		(22)		(44)
Balance at December 31		\$ (105)		\$ (162)		\$ (140)
Unrealized net holding (loss) gain on securities						
Balance at January 1		\$ (2)		\$ (29)		\$ (8)
Change during year		(3)		27		(21)
Balance at December 31		\$ (5)		\$ (2)		\$ (29)
Net derivatives (loss) gain on hedge transactions						
Balance at January 1		\$ (2)		\$ (2)		\$ (2)
Change during year		—		—		—
Balance at December 31		\$ (2)		\$ (2)		\$ (2)
Pension and other postretirement benefit plans						
Balance at January 1		\$ (3,677)		\$ (4,120)		\$ (4,753)
Change during year		200		443		633
Balance at December 31		\$ (3,477)		\$ (3,677)		\$ (4,120)
Balance at December 31		\$ (3,589)		\$ (3,843)		\$ (4,291)
Benefit Plan Trust (Common Stock)	14,168	(240)	14,168	(240)	14,168	(240)
Balance at December 31	14,168	\$ (240)	14,168	\$ (240)	14,168	\$ (240)
Treasury Stock at Cost						
Balance at January 1	551,170	\$ (41,834)	559,863	\$ (42,493)	563,028	\$ (42,733)
Purchases	10	(1)	20	(2)	15	(2)
Issuances - mainly employee benefit plans	(13,205)	1,002	(8,713)	661	(3,180)	242
Balance at December 31	537,975	\$ (40,833)	551,170	\$ (41,834)	559,863	\$ (42,493)
Total Chevron Corporation Stockholders' Equity at December 31		\$ 148,124		\$ 145,556		\$ 152,716
Noncontrolling Interests		\$ 1,195		\$ 1,166		\$ 1,170
Total Equity		\$ 149,319		\$ 146,722		\$ 153,886

See accompanying Notes to the Consolidated Financial Statements.

Note 1

Summary of Significant Accounting Policies

General The company's Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. These require the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Although the company uses its best estimates and judgments, actual results could differ from these estimates as future confirming events occur.

Subsidiary and Affiliated Companies The Consolidated Financial Statements include the accounts of controlled subsidiary companies more than 50 percent-owned and any variable-interest entities in which the company is the primary beneficiary. Undivided interests in oil and gas joint ventures and certain other assets are consolidated on a proportionate basis. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent, or for which the company exercises significant influence but not control over policy decisions, are accounted for by the equity method. As part of that accounting, the company recognizes gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity currently in income.

Investments in affiliates are assessed for possible impairment when events indicate that the fair value of the investment may be below the company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in net income. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. The new cost basis of investments in these equity investees is not changed for subsequent recoveries in fair value.

Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the various factors giving rise to the difference. When appropriate, the company's share of the affiliate's reported earnings is adjusted quarterly to reflect the difference between these allocated values and the affiliate's historical book values.

Fair Value Measurements The three levels of the fair value hierarchy of inputs the company uses to measure the fair value of an asset or a liability are as follows. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Level 3 inputs are inputs that are not observable in the market.

Derivatives The majority of the company's activity in derivative commodity instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's commodity trading activity, gains and losses from derivative instruments are reported in current income. 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 related to a portion of the company's fixed-rate debt, if any, may be accounted for as fair value hedges. Interest rate swaps related to floating-rate debt, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. Where Chevron is a party to master netting arrangements, fair value receivable and payable amounts recognized for derivative instruments executed with the same counterparty are generally offset on the balance sheet.

Short-Term Investments All short-term investments are classified as available for sale and are in highly liquid debt securities. Those investments that are part of the company's cash management portfolio and have original maturities of three months or less are reported as "Cash equivalents." Bank time deposits with maturities greater than 90 days are reported as "Time deposits." The balance of short-term investments is reported as "Marketable securities" and is marked-to-market, with any unrealized gains or losses included in "Other comprehensive income."

Inventories Crude oil, petroleum products and chemicals inventories are generally stated at cost, using a last-in, first-out method. In the aggregate, these costs are below market. "Materials, supplies and other" inventories are primarily stated at net realizable value.

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas

properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 21, beginning on page 62, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted, future net cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset (including changes to the commodity price forecast), significant change in the extent or manner of use of or a physical change in an asset, and a more-likely-than-not expectation that a long-lived asset or asset group will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted, future net cash flows. For proved crude oil and natural gas properties, the company performs impairment reviews on a country, concession, PSC, development area or field basis, as appropriate. In Downstream, impairment reviews are performed on the basis of a refinery, a plant, a marketing/lubricants area or distribution area, as appropriate. Impairment amounts are recorded as incremental “Depreciation, depletion and amortization” expense.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value. Refer to Note 10, beginning on page 46, relating to fair value measurements. The fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 26, on page 71, relating to AROs.

Depreciation and depletion of all capitalized costs of proved crude oil and natural gas producing properties, except mineral interests, are expensed using the unit-of-production method, generally by individual field, as the proved developed reserves are produced. Depletion expenses for capitalized costs of proved mineral interests are recognized using the unit-of-production method by individual field as the related proved reserves are produced. Impairments of capitalized costs of unproved mineral interests are expensed.

The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method is generally used to depreciate international plant and equipment and to amortize all capitalized leased assets.

Gains or losses are not recognized for normal retirements of properties, plant and equipment subject to composite group amortization or depreciation. Gains or losses from abnormal retirements are recorded as expenses, and from sales as “Other income.”

Expenditures for maintenance (including those for planned major maintenance projects), repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill resulting from a business combination is not subject to amortization. The company tests such goodwill at the reporting unit level for impairment annually at December 31, or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

Environmental Expenditures Environmental expenditures that relate to ongoing operations or to conditions caused by past operations are expensed. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For crude oil, natural gas and mineral-producing properties, a liability for an ARO is made in accordance with accounting standards for asset retirement and environmental obligations. Refer to Note 26, on page 71, for a discussion of the company’s AROs.

For federal Superfund sites and analogous sites under state laws, the company records a liability for its designated share of the probable and estimable costs, and probable amounts for other potentially responsible parties when mandated by the regulatory agencies because the other parties are not able to pay their respective shares. The gross amount of environmental liabilities is based on the company’s best estimate of future costs using currently available technology and applying current regulations and the company’s own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

Currency Translation The U.S. dollar is the functional currency for substantially all of the company’s consolidated operations and those of its equity affiliates. For those operations, all gains and losses from currency remeasurement are included in current period income. The cumulative translation effects for those few entities, both consolidated and affiliated, using functional currencies other than the U.S. dollar are included in “Currency translation adjustment” on the Consolidated Statement of Equity.

Revenue Recognition Revenues associated with sales of crude oil, natural gas, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized using the entitlement method. Excise, value-added and similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income, on page 34. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in “Purchased crude oil and products” on the Consolidated Statement of Income.

Stock Options and Other Share-Based Compensation The company issues stock options and other share-based compensation to certain employees. For equity awards, such as stock options, total compensation cost is based on the grant date fair value, and for liability awards, such as stock appreciation rights, total compensation cost is based on the settlement value. The company recognizes stock-based compensation expense for all awards over the service period required to earn the award, which is the shorter of the vesting period or the time period in which an employee becomes eligible to retain the award at retirement. The company’s Long-Term Incentive Plan (LTIP) awards include stock options and stock appreciation rights, which have graded vesting provisions by which one-third of each award vests on each of the first, second and third anniversaries of the date of grant. In addition, performance shares granted under the company’s LTIP will vest at the end of the three-year performance period. For awards granted under the company’s LTIP beginning in 2017, stock options and stock appreciation rights have graded vesting by which one third of each award vests annually on each January 31 on or after the first anniversary of the grant date. Standard restricted stock unit awards have cliff vesting by which the total award will vest on January 31 on or after the fifth anniversary of the grant date, subject to adjustment upon termination pursuant to the satisfaction of certain criteria. The company amortizes these awards on a straight-line basis.

Note 2

Changes in Accumulated Other Comprehensive Losses

The change in Accumulated Other Comprehensive Losses (AOCL) presented on the Consolidated Balance Sheet and the impact of significant amounts reclassified from AOCL on information presented in the Consolidated Statement of Income for the year ending December 31, 2017, are reflected in the table below.

	Year Ended December 31, 2017 ¹					
	Currency Translation Adjustments	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total	
Balance at January 1	\$ (162)	\$ (2)	\$ (2)	\$ (3,677)	\$ (3,843)	
Components of Other Comprehensive Income (Loss):						
Before Reclassifications	57	(3)	—	(310)	(256)	
Reclassifications ²	—	—	—	510	510	
Net Other Comprehensive Income (Loss)	57	(3)	—	200	254	
Balance at December 31	\$ (105)	\$ (5)	\$ (2)	\$ (3,477)	\$ (3,589)	

¹ All amounts are net of tax.

² Refer to Note 23 beginning on page 64, for reclassified components totaling \$796 that are included in employee benefit costs for the year ending December 31, 2017. Related income taxes for the same period, totaling \$286, are reflected in Income Tax Expense on the Consolidated Statement of Income. All other reclassified amounts were insignificant.

Note 3**Noncontrolling Interests**

Ownership interests in the company's subsidiaries held by parties other than the parent are presented separately from the parent's equity on the Consolidated Balance Sheet. The amount of consolidated net income attributable to the parent and the noncontrolling interests are both presented on the face of the Consolidated Statement of Income. The term "earnings" is defined as "Net Income (Loss) Attributable to Chevron Corporation."

Activity for the equity attributable to noncontrolling interests for 2017, 2016 and 2015 is as follows:

	2017	2016	2015
Balance at January 1	\$ 1,166	\$ 1,170	\$ 1,163
Net income	74	66	123
Distributions to noncontrolling interests	(78)	(63)	(128)
Other changes, net	33	(7)	12
Balance at December 31	\$ 1,195	\$ 1,166	\$ 1,170

Note 4**Information Relating to the Consolidated Statement of Cash Flows**

	Year ended December 31		
	2017	2016	2015
Net decrease (increase) in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	\$ (915)	\$ (2,121)	\$ 3,631
(Increase) decrease in inventories	(267)	603	85
Decrease in prepaid expenses and other current assets	252	439	713
Increase (decrease) in accounts payable and accrued liabilities	875	533	(5,769)
Increase (decrease) in income and other taxes payable	531	(4)	(639)
Net decrease (increase) in operating working capital	\$ 476	\$ (550)	\$ (1,979)
Net cash provided by operating activities includes the following cash payments for interest on debt and for income taxes:			
Interest on debt (net of capitalized interest)	\$ 265	\$ 158	\$ —
Income taxes	3,132	1,935	4,645
Net sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	\$ (3)	\$ (9)	\$ (6)
Marketable securities sold	7	306	128
Net sales of marketable securities	\$ 4	\$ 297	\$ 122
Net maturities of time deposits consisted of the following gross amounts:			
Investments in time deposits	\$ —	\$ —	\$ —
Maturities of time deposits	—	—	8
Net maturities of time deposits	\$ —	\$ —	\$ 8
Net (borrowing) repayment of loans by equity affiliates:			
Borrowing of loans by equity affiliates	\$ (142)	\$ (2,341)	\$ (223)
Repayment of loans by equity affiliates	126	307	6
Net (borrowing) repayment of loans by equity affiliates	\$ (16)	\$ (2,034)	\$ (217)
Net (purchases) sales of other short-term investments:			
Purchases of other short-term investments	\$ (41)	\$ (1)	\$ (75)
Sales of other short-term investments	9	218	119
Net (purchases) sales of other short-term investments	\$ (32)	\$ 217	\$ 44
Net borrowings (repayments) of short-term obligations consisted of the following gross and net amounts:			
Proceeds from issuances of short-term obligations	\$ 5,051	\$ 14,778	\$ 13,805
Repayments of short-term obligations	(8,820)	(12,558)	(16,379)
Net (repayments) borrowings of short-term obligations with three months or less maturity	(1,373)	(90)	2,239
Net (repayments) borrowings of short-term obligations	\$ (5,142)	\$ 2,130	\$ (335)

A loan to Tengizchevroil LLP for the development of the Future Growth and Wellhead Pressure Management Project represents the majority of "Net borrowing of loans by equity affiliates" in 2016.

The "Net sales of treasury shares" represents the cost of common shares acquired less the cost of shares issued for share-based compensation plans. Purchases totaled \$1, \$2 and \$2 in 2017, 2016 and 2015, respectively. No purchases were made under the company's share repurchase program in 2017, 2016, or 2015.

In 2017, 2016 and 2015, “Net (purchases) sales of other short-term investments” generally consisted of restricted cash associated with upstream abandonment activities, tax payments and certain pension fund payments that was invested in cash and short-term securities and reclassified from “Cash and cash equivalents” to “Deferred charges and other assets” on the Consolidated Balance Sheet.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2017, an approximate \$400 increase in “Deferred credits and other noncurrent obligations” and a corresponding increase to “Properties, plant and equipment, at cost” were considered non-cash transactions and excluded from “Net increase in operating working capital” and “Capital expenditures.” The amount is related to upstream operating agreements outside of the United States.

Refer also to Note 26, on page 71, for a discussion of revisions to the company’s AROs that also did not involve cash receipts or payments for the three years ending December 31, 2017.

The major components of “Capital expenditures” and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, are presented in the following table:

	Year ended December 31		
	2017	2016	2015
Additions to properties, plant and equipment *	\$ 13,222	\$ 17,742	\$ 28,213
Additions to investments	25	55	555
Current-year dry hole expenditures	157	313	736
Payments for other liabilities and assets, net	—	(1)	—
Capital expenditures	13,404	18,109	29,504
Expensed exploration expenditures	666	544	1,031
Assets acquired through capital lease obligations and other financing obligations	8	5	47
Capital and exploratory expenditures, excluding equity affiliates	14,078	18,658	30,582
Company’s share of expenditures by equity affiliates	4,743	3,770	3,397
Capital and exploratory expenditures, including equity affiliates	\$ 18,821	\$ 22,428	\$ 33,979

* Excludes noncash additions of \$1,183 in 2017, \$56 in 2016 and \$1,362 in 2015.

Note 5

New Accounting Standards

Revenue Recognition (Topic 606): Revenue from Contracts with Customers In July 2015, the FASB approved a one-year deferral of the effective date of ASU 2014-09, which becomes effective for the company January 1, 2018. The standard provides a single comprehensive revenue recognition model for contracts with customers, eliminates most industry-specific revenue recognition guidance, and expands disclosure requirements. The company has elected to adopt the standard using the modified retrospective transition method. “Sales and Other Operating Revenues” on the Consolidated Statement of Income includes excise, value-added and similar taxes on sales transactions. Upon adoption of the standard, revenue will exclude sales-based taxes collected on behalf of third parties, which will have no impact to earnings. The company completed its accounting policy and system enhancements necessary to meet the standard’s requirements. The company does not expect the implementation of the standard to have a material effect on its consolidated financial statements.

Leases (Topic 842) In February 2016, the FASB issued ASU 2016-02, which becomes effective for the company January 1, 2019. The standard requires that lessees present right-of-use assets and lease liabilities on the balance sheet. The company’s implementation efforts are focused on accounting policy and disclosure updates and system enhancements necessary to meet the standard’s requirements. The company is evaluating the effect of the standard on the company’s consolidated financial statements.

Financial Instruments - Credit Losses (Topic 326) In June 2016, the FASB issued ASU 2016-13, which becomes effective for the company beginning January 1, 2020. The standard requires companies to use forward-looking information to calculate credit loss estimates. The company is evaluating the effect of the standard on the company’s consolidated financial statements.

Intangibles - Goodwill and Other (Topic 350) In January 2017, the FASB issued ASU 2017-04. The standard simplifies the accounting for goodwill impairment, and the company has chosen to early adopt beginning January 1, 2017. Early adoption has no effect on the company’s consolidated financial statements.

Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20) In March 2017, the FASB issued ASU 2017-05, which becomes effective for the company January 1, 2018. The standard provides clarification regarding

the guidance on accounting for the derecognition of nonfinancial assets. The company does not expect the implementation of the standard to have a material effect on its consolidated financial statements.

Compensation - Retirement Benefits (Topic 715) In March 2017, the FASB issued ASU 2017-07, which becomes effective for the company January 1, 2018. The standard requires the disaggregation of the service cost component from the other components of net periodic benefit cost and allows only the service cost component of net benefit cost to be eligible for capitalization. The company does not expect the implementation of the standard to have a material effect on its consolidated financial statements.

Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued ASU 2016-15, which becomes effective for the company January 1, 2018 on a retrospective basis. The standard provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. The company does not expect the adoption of this ASU to have a material impact on its Consolidated Statement of Cash Flows.

Statement of Cash Flows (Topic 230) Restricted Cash In November 2016, the FASB issued ASU 2016-18, which becomes effective for the company January 1, 2018 on a retrospective basis. The standard requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents on the statement of cash flows and to provide a reconciliation to the balance sheet when the cash, cash equivalents, restricted cash and restricted cash equivalents are not separately presented or are presented in more than one line item on the balance sheet. Upon adoption, the company's restricted cash balances will be included in the beginning and ending balances on the Consolidated Statement of Cash Flows.

Note 6

Lease Commitments

Certain noncancellable leases are classified as capital leases, and the leased assets are included as part of "Properties, plant and equipment, at cost" on the Consolidated Balance Sheet. Such leasing arrangements involve crude oil production and processing equipment, service stations, bareboat charters, office buildings, and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on operating leases are recorded as expense. Details of the capitalized leased assets are as follows:

	At December 31	
	2017	2016
Upstream	\$ 678	\$ 676
Downstream	99	99
All Other	—	—
Total	777	775
Less: Accumulated amortization	515	383
Net capitalized leased assets	\$ 262	\$ 392

Rental expenses incurred for operating leases during 2017, 2016 and 2015 were as follows:

	Year ended December 31		
	2017	2016	2015
Minimum rentals	\$ 726	\$ 943	\$ 1,041
Contingent rentals	1	2	2
Total	727	945	1,043
Less: Sublease rental income	6	7	9
Net rental expense	\$ 721	\$ 938	\$ 1,034

Contingent rentals are based on factors other than the passage of time, principally sales volumes at leased service stations. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, renewal options ranging up to 25 years, and options to purchase the leased property during or at the end of the initial or renewal lease period for the fair market value or other specified amount at that time.

At December 31, 2017, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

Note 9

Summarized Financial Data – Chevron Phillips Chemical Company LLC

Chevron has a 50 percent equity ownership interest in Chevron Phillips Chemical Company LLC (CPChem). Refer to Note 16, beginning on page 52, for a discussion of CPChem operations. Summarized financial information for 100 percent of CPChem is presented in the table below:

	Year ended December 31		
	2017	2016	2015
Sales and other operating revenues	\$ 9,063	\$ 8,455	\$ 9,248
Costs and other deductions	8,126	7,017	7,136
Net income attributable to CPChem	1,446	1,687	2,651

	At December 31	
	2017	2016
Current assets	\$ 2,944	\$ 2,695
Other assets	13,823	12,770
Current liabilities	1,439	1,418
Other liabilities	2,932	2,569
Total CPChem net equity	\$ 12,396	\$ 11,478

Note 10

Fair Value Measurements

The tables below and on the next page show the fair value hierarchy for assets and liabilities measured at fair value on a recurring and nonrecurring basis at December 31, 2017, and December 31, 2016.

Marketable Securities The company calculates fair value for its marketable securities based on quoted market prices for identical assets. The fair values reflect the cash that would have been received if the instruments were sold at December 31, 2017.

Derivatives The company records its derivative instruments – other than any commodity derivative contracts that are designated as normal purchase and normal sale – on the Consolidated Balance Sheet at fair value, with the offsetting amount to the Consolidated Statement of Income. Derivatives classified as Level 1 include futures, swaps and options contracts traded in active markets such as the New York Mercantile Exchange. Derivatives classified as Level 2 include swaps, options and forward contracts principally with financial institutions and other oil and gas companies, the fair values of which are obtained from third-party broker quotes, industry pricing services and exchanges. The company obtains multiple sources of pricing information for the Level 2 instruments. Since this pricing information is generated from observable market data, it has historically been very consistent. The company does not materially adjust this information.

Properties, Plant and Equipment The company did not have any individually material impairments in 2017. The company reported impairments for certain oil and gas properties during 2016 primarily due to reservoir performance and lower crude oil prices. The impairments in 2016 were primarily in Brazil and the United States.

Investments and Advances The company did not have any individually material impairments of investments and advances in 2017 or 2016.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2017				At December 31, 2016			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	\$ 9	\$ 9	\$ —	\$ —	\$ 13	\$ 13	\$ —	\$ —
Derivatives	22	—	22	—	32	15	17	—
Total assets at fair value	\$ 31	\$ 9	\$ 22	\$ —	\$ 45	\$ 28	\$ 17	\$ —
Derivatives	124	78	46	—	109	78	31	—
Total liabilities at fair value	\$ 124	\$ 78	\$ 46	\$ —	\$ 109	\$ 78	\$ 31	\$ —

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

	At December 31					At December 31				
	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2017	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2016
Properties, plant and equipment, net (held and used)	\$ 603	\$ —	\$ —	\$ 603	\$ 658	\$ 582	\$ —	\$ 15	\$ 567	\$ 2,507
Properties, plant and equipment, net (held for sale)	1,378	—	1,378	—	363	891	—	888	3	679
Investments and advances	28	—	1	27	26	26	—	20	6	234
Total nonrecurring assets at fair value	\$ 2,009	\$ —	\$ 1,379	\$ 630	\$ 1,047	\$ 1,499	\$ —	\$ 923	\$ 576	\$ 3,420

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents and time deposits in U.S. and non-U.S. portfolios. The instruments classified as cash equivalents are primarily bank time deposits with maturities of 90 days or less and money market funds. “Cash and cash equivalents” had carrying/fair values of \$4,813 and \$6,988 at December 31, 2017, and December 31, 2016, respectively. The fair values of cash and cash equivalents are classified as Level 1 and reflect the cash that would have been received if the instruments were settled at December 31, 2017.

“Cash and cash equivalents” do not include investments with a carrying/fair value of \$1,130 and \$1,426 at December 31, 2017, and December 31, 2016, respectively. At December 31, 2017, these investments are classified as Level 1 and include restricted funds related to certain upstream abandonment activities, tax payments and refundable deposits related to pending asset sales, which are reported in “Deferred charges and other assets” on the Consolidated Balance Sheet. Long-term debt of \$23,477 and \$26,193 at December 31, 2017, and December 31, 2016, respectively, had estimated fair values of \$23,943 and \$26,627, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is \$23,245 and classified as Level 1. The fair value of other long-term debt is \$698 and classified as Level 2.

The carrying values of short-term financial assets and liabilities on the Consolidated Balance Sheet approximate their fair values. Fair value remeasurements of other financial instruments at December 31, 2017 and 2016, were not material.

Note 11**Financial and Derivative Instruments**

Derivative Commodity Instruments The company’s derivative commodity instruments principally include crude oil, natural gas and refined product futures, swaps, options, and forward contracts. None of the company’s derivative instruments is designated as a hedging instrument, although certain of the company’s affiliates make such designation. The company’s derivatives are not material to the company’s financial position, results of operations or liquidity. The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodity derivative activities.

The company uses derivative commodity instruments traded on the New York Mercantile Exchange and on electronic platforms of the Inter-Continental Exchange and Chicago Mercantile Exchange. In addition, the company enters into swap contracts and option contracts principally with major financial institutions and other oil and gas companies in the “over-the-counter” markets, which are governed by International Swaps and Derivatives Association agreements and other master netting arrangements. Depending on the nature of the derivative transactions, bilateral collateral arrangements may also be required.

Derivative instruments measured at fair value at December 31, 2017, December 31, 2016, and December 31, 2015, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are on the next page:

Consolidated Balance Sheet: Fair Value of Derivatives Not Designated as Hedging Instruments

Type of Contract	Balance Sheet Classification	At December 31	
		2017	2016
Commodity	Accounts and notes receivable, net	\$ 22	\$ 30
Commodity	Long-term receivables, net	—	2
Total assets at fair value		\$ 22	\$ 32
Commodity	Accounts payable	\$ 122	\$ 99
Commodity	Deferred credits and other noncurrent obligations	2	10
Total liabilities at fair value		\$ 124	\$ 109

Consolidated Statement of Income: The Effect of Derivatives Not Designated as Hedging Instruments

Type of Derivative Contract	Statement of Income Classification	Gain/(Loss) Year ended December 31		
		2017	2016	2015
Commodity	Sales and other operating revenues	\$ (105)	\$ (269)	\$ 277
Commodity	Purchased crude oil and products	(9)	(31)	30
Commodity	Other income	(2)	—	(3)
		\$ (116)	\$ (300)	\$ 304

The table below represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2017 and December 31, 2016.

Consolidated Balance Sheet: The Effect of Netting Derivative Assets and Liabilities

At December 31, 2017	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset	Net Amounts
Derivative Assets	\$ 1,169	\$ 1,147	\$ 22	\$ —	\$ 22
Derivative Liabilities	\$ 1,271	\$ 1,147	\$ 124	\$ —	\$ 124
At December 31, 2016					
Derivative Assets	\$ 1,052	\$ 1,020	\$ 32	\$ —	\$ 32
Derivative Liabilities	\$ 1,129	\$ 1,020	\$ 109	\$ —	\$ 109

Derivative assets and liabilities are classified on the Consolidated Balance Sheet as accounts and notes receivable, long-term receivables, accounts payable, and deferred credits and other noncurrent obligations. Amounts not offset on the Consolidated Balance Sheet represent positions that do not meet all the conditions for “a right of offset.”

Concentrations of Credit Risk The company’s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, marketable securities, derivative financial instruments and trade receivables. The company’s short-term investments are placed with a wide array of financial institutions with high credit ratings. Company investment policies limit the company’s exposure both to credit risk and to concentrations of credit risk. Similar policies on diversification and creditworthiness are applied to the company’s counterparties in derivative instruments.

The trade receivable balances, reflecting the company’s diversified sources of revenue, are dispersed among the company’s broad customer base worldwide. As a result, the company believes concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, alternative risk mitigation measures may be deployed, including requiring pre-payments, letters of credit or other acceptable collateral instruments to support sales to customers.

Note 12**Assets Held for Sale**

At December 31, 2017, the company classified \$640 of net properties, plant and equipment as “Assets held for sale” on the Consolidated Balance Sheet. These assets are primarily associated with downstream and upstream operations that are anticipated to be sold in the next 12 months. The revenues and earnings contributions of these assets in 2017 were not material.

Note 13**Equity**

Retained earnings at December 31, 2017 and 2016, included approximately \$18,473 and \$16,479, respectively, for the company’s share of undistributed earnings of equity affiliates.

At December 31, 2017, about 82 million shares of Chevron's common stock remained available for issuance from the 260 million shares that were reserved for issuance under the Chevron Long-Term Incentive Plan. In addition, 800,468 shares remain available for issuance from the 1,600,000 shares of the company's common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan.

Note 14

Earnings Per Share

Basic earnings per share (EPS) is based upon "Net Income (Loss) Attributable to Chevron Corporation" ("earnings") and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (refer to Note 22, "Stock Options and Other Share-Based Compensation," beginning on page 63). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2017	2016	2015
Basic EPS Calculation			
Earnings available to common stockholders - Basic ¹	\$ 9,195	\$ (497)	\$ 4,587
Weighted-average number of common shares outstanding ²	1,882	1,872	1,867
Add: Deferred awards held as stock units	1	1	1
Total weighted-average number of common shares outstanding	1,883	1,873	1,868
Earnings per share of common stock - Basic	\$ 4.88	\$ (0.27)	\$ 2.46
Diluted EPS Calculation			
Earnings available to common stockholders - Diluted ¹	\$ 9,195	\$ (497)	\$ 4,587
Weighted-average number of common shares outstanding ²	1,882	1,872	1,867
Add: Deferred awards held as stock units	1	1	1
Add: Dilutive effect of employee stock-based awards	15	—	7
Total weighted-average number of common shares outstanding	1,898	1,873	1,875
Earnings per share of common stock - Diluted	\$ 4.85	\$ (0.27)	\$ 2.45

¹ There was no effect of dividend equivalents paid on stock units or dilutive impact of employee stock-based awards on earnings.

² Millions of shares; 10 million shares of employee-based awards were not included in the 2016 diluted EPS calculation as the result would be anti-dilutive.

Note 15

Operating Segments and Geographic Data

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. The investments are grouped into two business segments, Upstream and Downstream, representing the company's "reportable segments" and "operating segments." Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; liquefaction, transportation and regasification associated with liquefied natural gas (LNG); transporting crude oil by major international oil export pipelines; processing, transporting, storage and marketing of natural gas; and a gas-to-liquids plant. Downstream operations consist primarily of refining of crude oil into petroleum products; marketing of crude oil and refined products; transporting of 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. All Other activities of the company include worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.

The company's segments are managed by "segment managers" who report to the "chief operating decision maker" (CODM). The segments represent components of the company that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and assesses their performance; and (c) for which discrete financial information is available.

The company's primary country of operation is the United States of America, its country of domicile. Other components of the company's operations are reported as "International" (outside the United States).

Segment Earnings The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments. However, operating segments are billed for the direct use of corporate services. Nonbillable costs remain at the corporate level in “All Other.” Earnings by major operating area are presented in the following table:

	Year ended December 31		
	2017	2016	2015
Upstream			
United States	\$ 3,640	\$ (2,054)	\$ (4,055)
International	4,510	(483)	2,094
Total Upstream	8,150	(2,537)	(1,961)
Downstream			
United States	2,938	1,307	3,182
International	2,276	2,128	4,419
Total Downstream	5,214	3,435	7,601
Total Segment Earnings	13,364	898	5,640
All Other			
Interest expense	(264)	(168)	—
Interest income	60	58	65
Other	(3,965)	(1,285)	(1,118)
Net Income (Loss) Attributable to Chevron Corporation	\$ 9,195	\$ (497)	\$ 4,587

Segment Assets Segment assets do not include intercompany investments or receivables. Assets at year-end 2017 and 2016 are as follows:

	At December 31	
	2017	2016
Upstream		
United States	\$ 40,770	\$ 42,596
International	159,612	164,068
Goodwill	4,531	4,581
Total Upstream	204,913	211,245
Downstream		
United States	23,202	22,264
International	17,434	15,816
Total Downstream	40,636	38,080
Total Segment Assets	245,549	249,325
All Other		
United States	4,938	4,852
International	3,319	5,901
Total All Other	8,257	10,753
Total Assets – United States	68,910	69,712
Total Assets – International	180,365	185,785
Goodwill	4,531	4,581
Total Assets	\$ 253,806	\$ 260,078

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2017, 2016 and 2015, are presented in the table on the next page. Products are transferred between operating segments at internal product values that approximate market prices.

Revenues for the upstream segment are derived primarily from the production and sale of crude oil and natural gas, as well as the sale of third-party production of natural gas. Revenues for the downstream segment are derived from the refining and marketing of petroleum products such as gasoline, jet fuel, gas oils, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the manufacture and sale of fuel and lubricant additives and the transportation and trading of refined products and crude oil. “All Other” activities include revenues from insurance operations, real estate activities and technology companies.

Notes to the Consolidated Financial Statements

Millions of dollars, except per-share amounts

	Year ended December 31*		
	2017	2016	2015
Upstream			
United States	\$ 3,901	\$ 3,148	\$ 4,117
Intersegment	9,341	7,217	8,631
Total United States	13,242	10,365	12,748
International	17,209	13,262	15,587
Intersegment	11,471	9,518	11,492
Total International	28,680	22,780	27,079
Total Upstream	41,922	33,145	39,827
Downstream			
United States	48,728	40,366	48,420
Excise and similar taxes	4,398	4,335	4,426
Intersegment	14	16	26
Total United States	53,140	44,717	52,872
International	57,438	46,388	54,296
Excise and similar taxes	2,791	2,570	2,933
Intersegment	1,166	1,068	1,528
Total International	61,395	50,026	58,757
Total Downstream	114,535	94,743	111,629
All Other			
United States	208	145	141
Intersegment	814	960	1,372
Total United States	1,022	1,105	1,513
International	1	1	5
Intersegment	25	36	37
Total International	26	37	42
Total All Other	1,048	1,142	1,555
Segment Sales and Other Operating Revenues			
United States	67,404	56,187	67,133
International	90,101	72,843	85,878
Total Segment Sales and Other Operating Revenues	157,505	129,030	153,011
Elimination of intersegment sales	(22,831)	(18,815)	(23,086)
Total Sales and Other Operating Revenues	\$ 134,674	\$ 110,215	\$ 129,925

* Other than the United States, no other country accounted for 10 percent or more of the company's Sales and Other Operating Revenues.

Segment Income Taxes Segment income tax expense for the years 2017, 2016 and 2015 is as follows:

	Year ended December 31		
	2017	2016	2015
Upstream			
United States	\$ (3,538)	\$ (1,172)	\$ (2,041)
International	2,249	166	1,214
Total Upstream	(1,289)	(1,006)	(827)
Downstream			
United States	(419)	503	1,320
International	650	484	1,313
Total Downstream	231	987	2,633
All Other	1,010	(1,710)	(1,674)
Total Income Tax Expense (Benefit)	\$ (48)	\$ (1,729)	\$ 132

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 16, on page 52. Information related to properties, plant and equipment by segment is contained in Note 24, on page 69.

Note 16**Investments and Advances**

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, is shown in the following table. For certain equity affiliates, Chevron pays its share of some income taxes directly. For such affiliates, the equity in earnings does not include these taxes, which are reported on the Consolidated Statement of Income as “Income tax expense.”

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2017	2016	2017	2016	2015
Upstream					
Tengizchevroil	\$ 13,121	\$ 11,414	\$ 2,581	\$ 1,380	\$ 1,939
Petropiar	1,152	977	175	326	180
Caspian Pipeline Consortium	1,151	1,245	155	145	162
Petroboscan	1,080	982	154	(133)	219
Angola LNG Limited	2,625	2,744	31	(282)	(417)
Other	1,714	1,791	100	(193)	135
Total Upstream	20,843	19,153	3,196	1,243	2,218
Downstream					
GS Caltex Corporation	3,826	3,767	290	373	824
Chevron Phillips Chemical Company LLC	6,200	5,767	723	840	1,367
Caltex Australia Ltd.	—	—	—	—	92
Other	1,251	1,118	230	209	186
Total Downstream	11,277	10,652	1,243	1,422	2,469
All Other					
Other	(15)	(16)	(1)	(4)	(3)
Total equity method	32,105	\$ 29,789	\$ 4,438	\$ 2,661	\$ 4,684
Other at or below cost	392	461			
Total investments and advances	\$ 32,497	\$ 30,250			
Total United States	\$ 7,582	\$ 7,258	\$ 788	\$ 802	\$ 1,342
Total International	\$ 24,915	\$ 22,992	\$ 3,650	\$ 1,859	\$ 3,342

Descriptions of major affiliates, including significant differences between the company’s carrying value of its investments and its underlying equity in the net assets of the affiliates, are as follows:

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), which operates the Tengiz and Korolev crude oil fields in Kazakhstan. At December 31, 2017, the company’s carrying value of its investment in TCO was about \$130 higher than the amount of underlying equity in TCO’s net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO’s net assets. Included in the investment is a loan to TCO to fund the development of the Future Growth and Wellhead Pressure Management Project with a balance of \$2,060, including accrued interest. See Note 8, on page 45, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company which operates the Hamaca heavy-oil production and upgrading project in Venezuela’s Orinoco Belt. At December 31, 2017, the company’s carrying value of its investment in Petropiar was approximately \$145 less than the amount of underlying equity in Petropiar’s net assets. The difference represents the excess of Chevron’s underlying equity in Petropiar’s net assets over the net book value of the assets contributed to the venture.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, a variable interest entity, which provides the critical export route for crude oil from both TCO and Karachaganak. The company has investments and advances totaling \$1,151, which includes long-term loans of \$727 at year-end 2017. The loans were provided to fund 30 percent of the initial pipeline construction. The company is not the primary beneficiary of the consortium because it does not direct activities of the consortium and only receives its proportionate share of the financial returns.

Petroboscan Chevron has a 39.2 percent interest in Petroboscan, a joint stock company which operates the Boscan Field in Venezuela. At December 31, 2017, the company’s carrying value of its investment in Petroboscan was approximately \$105 higher than the amount of underlying equity in Petroboscan’s net assets. The difference reflects the excess of the net book value of the assets contributed by Chevron over its underlying equity in Petroboscan’s net assets. The company also has an outstanding long-term loan to Petroboscan of \$686 at year-end 2017.

Angola LNG Limited Chevron has a 36.4 percent interest in Angola LNG Limited, which processes and liquefies natural gas produced in Angola for delivery to international markets.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex Corporation, a joint venture with GS Energy. The joint venture imports, refines and markets petroleum products, petrochemicals and lubricants, predominantly in South Korea.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC. The other half is owned by Phillips 66.

Other Information “Sales and other operating revenues” on the Consolidated Statement of Income includes \$8,165, \$5,786 and \$4,850 with affiliated companies for 2017, 2016 and 2015, respectively. “Purchased crude oil and products” includes \$4,800, \$3,468 and \$4,240 with affiliated companies for 2017, 2016 and 2015, respectively.

“Accounts and notes receivable” on the Consolidated Balance Sheet includes \$1,141 and \$676 due from affiliated companies at December 31, 2017 and 2016, respectively. “Accounts payable” includes \$498 and \$383 due to affiliated companies at December 31, 2017 and 2016, respectively.

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron’s total share, which includes Chevron’s net loans to affiliates of \$3,853, \$3,535 and \$410 at December 31, 2017, 2016 and 2015, respectively.

Year ended December 31	Affiliates			Chevron Share		
	2017	2016	2015	2017	2016	2015
Total revenues	\$ 70,744	\$ 59,253	\$ 71,389	\$ 33,460	\$ 27,787	\$ 33,492
Income before income tax expense	13,487	6,587	13,129	5,712	3,670	6,279
Net income attributable to affiliates	10,751	5,127	10,649	4,468	2,876	4,691
At December 31						
Current assets	\$ 33,883	\$ 33,406	\$ 27,162	\$ 13,568	\$ 13,743	\$ 10,657
Noncurrent assets	82,261	75,258	71,650	32,643	28,854	26,607
Current liabilities	26,873	24,793	20,559	10,201	8,996	7,351
Noncurrent liabilities	21,447	22,671	18,560	4,224	4,255	3,909
Total affiliates’ net equity	\$ 67,824	\$ 61,200	\$ 59,693	\$ 31,786	\$ 29,346	\$ 26,004

Note 17 Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to eight pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company’s ultimate exposure related to pending lawsuits and claims is not determinable. The company no longer uses MTBE in the manufacture of gasoline in the United States.

Ecuador

Background Chevron is a defendant in a civil lawsuit initiated in the Superior Court of Nueva Loja in Lago Agrio, Ecuador, in May 2003 by plaintiffs who claim to be representatives of certain residents of an area where an oil production consortium formerly had operations. The lawsuit alleges damage to the environment from the oil exploration and production operations and seeks unspecified damages to fund environmental remediation and restoration of the alleged environmental harm, plus a health monitoring program. Until 1992, Texaco Petroleum Company (Texpet), a subsidiary of Texaco Inc., was a minority member of this consortium with Petroecuador, the Ecuadorian state-owned oil company, as the majority partner; since 1990, the operations have been conducted solely by Petroecuador. At the conclusion of the consortium and following an independent third-party environmental audit of the concession area, Texpet entered into a formal agreement with the Republic of Ecuador and Petroecuador for Texpet to remediate specific sites assigned by the government in proportion to Texpet’s ownership share of the consortium. Pursuant to that agreement, Texpet conducted a three-year remediation program at a cost of \$40. After certifying that the sites were properly remediated, the government granted Texpet and all related corporate entities a full release from any and all environmental liability arising from the consortium operations.

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in

Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously given to Texpet by the Republic of Ecuador and Petroecuador and by the pertinent provincial and municipal governments. With regard to the facts, the company believes that the evidence confirms that Texpet's remediation was properly conducted and that the remaining environmental damage reflects Petroecuador's failure to timely fulfill its legal obligations and Petroecuador's further conduct since assuming full control over the operations.

Lago Agrio Judgment In 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess \$18,900, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer's report also asserted that an additional \$8,400 could be assessed against Chevron for unjust enrichment. In 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case was recused. In 2010, Chevron moved to strike the mining engineer's report and to dismiss the case based on evidence obtained through discovery in the United States indicating that the report was prepared by consultants for the plaintiffs before being presented as the mining engineer's independent and impartial work and showing further evidence of misconduct. In August 2010, the judge issued an order stating that he was not bound by the mining engineer's report and requiring the parties to provide their positions on damages within 45 days. Chevron subsequently petitioned for recusal of the judge, claiming that he had disregarded evidence of fraud and misconduct and that he had failed to rule on a number of motions within the statutory time requirement.

In September 2010, Chevron submitted its position on damages, asserting that no amount should be assessed against it. The plaintiffs' submission, which relied in part on the mining engineer's report, took the position that damages are between approximately \$16,000 and \$76,000 and that unjust enrichment should be assessed in an amount between approximately \$5,000 and \$38,000. The next day, the judge issued an order closing the evidentiary phase of the case and notifying the parties that he had requested the case file so that he could prepare a judgment. Chevron petitioned to have that order declared a nullity in light of Chevron's prior recusal petition, and because procedural and evidentiary matters remained unresolved. In October 2010, Chevron's motion to recuse the judge was granted. A new judge took charge of the case and revoked the prior judge's order closing the evidentiary phase of the case. On December 17, 2010, the judge issued an order closing the evidentiary phase of the case and notifying the parties that he had requested the case file so that he could prepare a judgment.

On February 14, 2011, the provincial court in Lago Agrio rendered an adverse judgment in the case. The court rejected Chevron's defenses to the extent the court addressed them in its opinion. The judgment assessed approximately \$8,600 in damages and approximately \$900 as an award for the plaintiffs' representatives. It also assessed an additional amount of approximately \$8,600 in punitive damages unless the company issued a public apology within 15 days of the judgment, which Chevron did not do. On February 17, 2011, the plaintiffs appealed the judgment, seeking increased damages, and on March 11, 2011, Chevron appealed the judgment seeking to have the judgment nullified. On January 3, 2012, an appellate panel in the provincial court affirmed the February 14, 2011 decision and ordered that Chevron pay additional attorneys' fees in the amount of "0.10% of the values that are derived from the decisional act of this judgment." The plaintiffs filed a petition to clarify and amplify the appellate decision on January 6, 2012, and the court issued a ruling in response on January 13, 2012, purporting to clarify and amplify its January 3, 2012 ruling, which included clarification that the deadline for the company to issue a public apology to avoid the additional amount of approximately \$8,600 in punitive damages was within 15 days of the clarification ruling, or February 3, 2012. Chevron did not issue an apology because doing so might be mischaracterized as an admission of liability and would be contrary to facts and evidence submitted at trial. On January 20, 2012, Chevron appealed (called a petition for cassation) the appellate panel's decision to Ecuador's National Court of Justice. As part of the appeal, Chevron requested the suspension of any requirement that Chevron post a bond to prevent enforcement under Ecuadorian law of the judgment during the cassation appeal. On February 17, 2012, the appellate panel of the provincial court admitted Chevron's cassation appeal in a procedural step necessary for the National Court of Justice to hear the appeal. The provincial court appellate panel denied Chevron's request for suspension of the requirement that Chevron post a bond and stated that it would not comply with the First and Second Interim Awards of the international arbitration tribunal discussed below. On March 29, 2012, the matter was transferred from the provincial court to the National Court of Justice, and on November 22, 2012, the National Court agreed to hear Chevron's cassation appeal. On August 3, 2012, the provincial court in Lago Agrio approved a court-appointed liquidator's report on damages that calculated the total judgment in the case to be \$19,100. On November 13, 2013, the National Court ratified the judgment but nullified the \$8,600 punitive damage assessment, resulting in a judgment of \$9,500. On December 23, 2013, Chevron appealed the decision to the Ecuador Constitutional Court, Ecuador's highest court. The reporting justice of the Constitutional Court heard oral arguments on the appeal on July 16, 2015.

Lago Agrio Plaintiffs' Enforcement Actions Chevron has no assets in Ecuador and the Lago Agrio plaintiffs' lawyers have stated in press releases and through other media that they will seek to enforce the Ecuadorian judgment in various countries and otherwise disrupt Chevron's operations. On May 30, 2012, the Lago Agrio plaintiffs filed an action against Chevron Corporation, Chevron Canada Limited, and Chevron Canada Finance Limited in the Ontario Superior Court of Justice in Ontario, Canada, seeking to recognize and enforce the Ecuadorian judgment. On May 1, 2013, the Ontario Superior Court of Justice held that the Court has jurisdiction over Chevron and Chevron Canada Limited for purposes of the action, but stayed the action due to the absence of evidence that Chevron Corporation has assets in Ontario. The Lago Agrio plaintiffs appealed that decision and on December 17, 2013, the Court of Appeals for Ontario affirmed the lower court's decision on jurisdiction and set aside the stay, allowing the recognition and enforcement action to be heard in the Ontario Superior Court of Justice. Chevron appealed the decision to the Supreme Court of Canada and, on September 4, 2015, the Supreme Court dismissed the appeal and affirmed that the Ontario Superior Court of Justice has jurisdiction over Chevron and Chevron Canada Limited for purposes of the action. The recognition and enforcement proceeding and related preliminary motions are proceeding in the Ontario Superior Court of Justice. On January 20, 2017, the Ontario Superior Court of Justice granted Chevron Canada Limited's and Chevron Corporation's motions for summary judgment, concluding that the two companies are separate legal entities with separate rights and obligations. As a result, the Superior Court dismissed the recognition and enforcement claim against Chevron Canada Limited. Chevron Corporation still remains as a defendant in the action. On February 3, 2017, the Lago Agrio plaintiffs appealed the Superior Court's January 20, 2017 decision.

On June 27, 2012, the Lago Agrio plaintiffs filed a complaint against Chevron Corporation in the Superior Court of Justice in Brasilia, Brazil, seeking to recognize and enforce the Ecuadorian judgment. Chevron has answered the complaint. In accordance with Brazilian procedure, the matter was referred to the public prosecutor for a nonbinding opinion of the issues raised in the complaint. On May 13, 2015, the public prosecutor issued its nonbinding opinion and recommended that the Superior Court of Justice reject the plaintiffs' recognition and enforcement request, finding, among other things, that the Lago Agrio judgment was procured through fraud and corruption and cannot be recognized in Brazil because it violates Brazilian and international public order. On November 29, 2017, the Superior Court of Justice issued a decision dismissing the Lago Agrio plaintiffs' recognition and enforcement proceeding based on jurisdictional grounds.

On October 15, 2012, the provincial court in Lago Agrio issued an ex parte embargo order that purports to order the seizure of assets belonging to separate Chevron subsidiaries in Ecuador, Argentina and Colombia. On November 6, 2012, at the request of the Lago Agrio plaintiffs, a court in Argentina issued a Freeze Order against Chevron Argentina S.R.L. and another Chevron subsidiary, Ingeniero Norberto Priu, requiring shares of both companies to be "embargoed," requiring third parties to withhold 40 percent of any payments due to Chevron Argentina S.R.L. and ordering banks to withhold 40 percent of the funds in Chevron Argentina S.R.L. bank accounts. On December 14, 2012, the Argentinean court rejected a motion to revoke the Freeze Order but modified it by ordering that third parties are not required to withhold funds but must report their payments. The court also clarified that the Freeze Order relating to bank accounts excludes taxes. On January 30, 2013, an appellate court upheld the Freeze Order, but on June 4, 2013 the Supreme Court of Argentina revoked the Freeze Order in its entirety. On December 12, 2013, the Lago Agrio plaintiffs served Chevron with notice of their filing of an enforcement proceeding in the National Court, First Instance, of Argentina. Chevron filed its answer on February 27, 2014, to which the Lago Agrio plaintiffs responded on December 29, 2015. On April 19, 2016, the public prosecutor in Argentina issued a non-binding opinion recommending to the National Court, First Instance, of Argentina that it reject the Lago Agrio plaintiffs' request to recognize the Ecuadorian judgment in Argentina. On February 24, 2017, the public prosecutor in Argentina issued a supplemental opinion reaffirming its previous recommendations. On November 1, 2017, the National Court, First Instance, of Argentina issued a decision dismissing the Lago Agrio plaintiffs' recognition and enforcement proceeding based on jurisdictional grounds. On November 2, 2017, the Lago Agrio plaintiffs appealed this decision to the Federal Civil Court of Appeals.

Chevron continues to believe the provincial court's judgment is illegitimate and unenforceable in Ecuador, the United States and other countries. The company also believes the judgment is the product of fraud, and contrary to the legitimate scientific evidence. Chevron cannot predict the timing or ultimate outcome of the appeals process in Ecuador or any enforcement action. Chevron expects to continue a vigorous defense of any imposition of liability in the Ecuadorian courts and to contest and defend any and all enforcement actions.

Company's Bilateral Investment Treaty Arbitration Claims Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before an arbitral tribunal presiding in the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador's obligations under the United States–Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment

agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador's obligations under the BIT. On January 25, 2012, the Tribunal issued its First Interim Measures Award requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. On February 16, 2012, the Tribunal issued a Second Interim Award mandating that the Republic of Ecuador take all measures necessary (whether by its judicial, legislative or executive branches) to suspend or cause to be suspended the enforcement and recognition within and without Ecuador of the judgment against Chevron. On February 27, 2012, the Tribunal issued a Third Interim Award confirming its jurisdiction to hear Chevron's arbitration claims. On February 7, 2013, the Tribunal issued its Fourth Interim Award in which it declared that the Republic of Ecuador "has violated the First and Second Interim Awards under the [BIT], the UNCITRAL Rules and international law in regard to the finalization and enforcement subject to execution of the Lago Agrio Judgment within and outside Ecuador, including (but not limited to) Canada, Brazil and Argentina." The Republic of Ecuador subsequently filed in the District Court of the Hague a request to set aside the Tribunal's Interim Awards and the First Partial Award (described below), and on January 20, 2016, the District Court denied the Republic's request. On April 13, 2016, the Republic of Ecuador appealed the decision. On July 18, 2017, the Appeals Court of the Hague denied the Republic's appeal. On October 18, 2017, the Republic appealed the decision of the Appeals Court of the Hague to the Supreme Court of the Netherlands.

The Tribunal has divided the merits phase of the proceeding into three phases. On September 17, 2013, the Tribunal issued its First Partial Award from Phase One, finding that the settlement agreements between the Republic of Ecuador and Texpet applied to Texpet and Chevron, released Texpet and Chevron from claims based on "collective" or "diffuse" rights arising from Texpet's operations in the former concession area and precluded third parties from asserting collective/diffuse rights environmental claims relating to Texpet's operations in the former concession area but did not preclude individual claims for personal harm. The Tribunal held a hearing on April 29-30, 2014, to address remaining issues relating to Phase One, and on March 12, 2015, it issued a nonbinding decision that the Lago Agrio plaintiffs' complaint, on its face, includes claims not barred by the settlement agreement between the Republic of Ecuador and Texpet. In the same decision, the Tribunal deferred to Phase Two remaining issues from Phase One, including whether the Republic of Ecuador breached the 1995 settlement agreement and the remedies that are available to Chevron and Texpet as a result of that breach. Phase Two issues were addressed at a hearing held in April and May 2015. The Tribunal has not set a date for Phase Three, the damages phase of the arbitration.

Company's RICO Action Through a series of U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters, alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron sought relief that included a declaration that any judgment against Chevron in the Lago Agrio litigation is the result of fraud and other unlawful conduct and is therefore unenforceable. The trial commenced on October 15, 2013 and concluded on November 22, 2013. On March 4, 2014, the Federal District Court entered a judgment in favor of Chevron, prohibiting the defendants from seeking to enforce the Lago Agrio judgment in the United States and further prohibiting them from profiting from their illegal acts. The defendants appealed the Federal District Court's decision, and, on April 20, 2015, a panel of the U.S. Court of Appeals for the Second Circuit heard oral arguments. On August 8, 2016, the Second Circuit issued a unanimous opinion affirming in full the judgment of the Federal District Court in favor of Chevron. On October 27, 2016, the Second Circuit denied the defendants' petitions for en banc rehearing of the opinion on their appeal. On March 27, 2017, two of the defendants filed a petition for a Writ of Certiorari to the United States Supreme Court. On June 19, 2017, the United States Supreme Court denied the defendants' petition for a Writ of Certiorari.

Management's Assessment The ultimate outcome of the foregoing matters, including any financial effect on Chevron, remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this case. Due to the defects associated with the Ecuadorian judgment, the 2008 engineer's report on alleged damages and the September 2010 plaintiffs' submission on alleged damages, management does not believe these documents have any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

Note 18

Taxes

	Year ended December 31		
	2017	2016	2015
Income Taxes			
Income tax expense (benefit)			
U.S. federal			
Current	\$ (382)	\$ (623)	\$ (817)
Deferred	(2,561)	(1,558)	(580)
State and local			
Current	(97)	(15)	(187)
Deferred	66	(121)	(109)
Total United States	(2,974)	(2,317)	(1,693)
International			
Current	3,634	2,744	2,997
Deferred	(708)	(2,156)	(1,172)
Total International	2,926	588	1,825
Total income tax expense (benefit)	\$ (48)	\$ (1,729)	\$ 132

The reconciliation between the U.S. statutory federal income tax rate and the company's effective income tax rate is detailed in the following table:

	2017	2016	2015
Income (loss) before income taxes			
United States	\$ (441)	\$ (4,317)	\$ (2,877)
International	9,662	2,157	7,719
Total income (loss) before income taxes	9,221	(2,160)	4,842
Theoretical tax (at U.S. statutory rate of 35%)	3,227	(756)	1,695
Effect of U.S. tax reform	(2,020)	—	—
Equity affiliate accounting effect	(1,373)	(704)	(1,286)
Effect of income taxes from international operations*	(130)	608	72
State and local taxes on income, net of U.S. federal income tax benefit	39	(44)	(74)
Prior year tax adjustments, claims and settlements	(39)	(349)	84
Tax credits	(199)	(188)	(35)
Other U.S.*	447	(296)	(324)
Total income tax expense (benefit)	\$ (48)	\$ (1,729)	\$ 132
Effective income tax rate	(0.5)%	80.0%	2.7%

* Includes one-time tax costs (benefits) associated with changes in uncertain tax positions and valuation allowances.

The 2017 decline in income tax benefit of \$1,681, from a benefit of \$1,729 in 2016 to a benefit of \$48 in 2017, is a result of the year-over-year increase in total income before income tax expense, which is primarily due to effects of higher crude oil prices and gains on asset sales primarily in Indonesia and Canada. In addition, the tax benefit for the year includes a provisional benefit of \$2,020 from U.S. tax reform, which primarily reflects the remeasurement of U.S. deferred tax assets and liabilities. The company's effective tax rate changed from 80 percent in 2016 to (0.5) percent in 2017. The change in effective tax rate is primarily a consequence of the mix effect resulting from the absolute level of earnings or losses and whether they arose in higher or lower tax rate jurisdictions and the 2017 impact of U.S. tax reform.

As noted above, U.S. tax reform resulted in the remeasurement of U.S. deferred tax assets and liabilities. The final impact will not be known until the actual 2017 U.S. tax return is submitted in 2018, and this may result in a change to the provisional amounts that have been recognized.

The company records its deferred taxes on a tax-jurisdiction basis. The reported deferred tax balances are composed of the following:

	At December 31	
	2017	2016
Deferred tax liabilities		
Properties, plant and equipment	\$ 19,869	\$ 25,180
Investments and other	4,796	5,222
Total deferred tax liabilities	24,665	30,402
Deferred tax assets		
Foreign tax credits	(11,872)	(10,976)
Asset retirement obligations/environmental reserves	(5,511)	(6,251)
Employee benefits	(3,129)	(4,392)
Deferred credits	(1,769)	(1,950)
Tax loss carryforwards	(5,463)	(6,030)
Other accrued liabilities	(842)	(510)
Inventory	(336)	(374)
Miscellaneous	(2,415)	(3,121)
Total deferred tax assets	(31,337)	(33,604)
Deferred tax assets valuation allowance	16,574	16,069
Total deferred taxes, net	\$ 9,902	\$ 12,867

Deferred tax liabilities at the end of 2017 decreased by approximately \$5,700 from year-end 2016. The decrease was primarily related to property, plant and equipment temporary differences mainly due to the change in the enacted U.S. tax rate.

Deferred tax assets decreased by approximately \$2,300 in 2017. Decreases were mainly due to the change in the enacted U.S. tax rate and primarily impacted asset retirement obligations, employee benefits and tax loss carry forwards. The decrease was partially reduced by an increase in foreign tax credits arising from earnings in high-tax rate international jurisdictions, which was substantially offset by valuation allowances.

The overall valuation allowance relates to deferred tax assets for U.S. foreign tax credit carryforwards, tax loss carryforwards and temporary differences. It reduces the deferred tax assets to amounts that are, in management's assessment, more likely than not to be realized. At the end of 2017, the company had tax loss carryforwards of approximately \$16,102 and tax credit carryforwards of approximately \$1,379, primarily related to various international tax jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2018 through 2034. U.S. foreign tax credit carryforwards of \$11,872 will expire between 2018 and 2027.

At December 31, 2017 and 2016, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2017	2016
Deferred charges and other assets	\$ (4,750)	\$ (4,649)
Noncurrent deferred income taxes	14,652	17,516
Total deferred income taxes, net	\$ 9,902	\$ 12,867

Enactment of U.S. tax reform imposed a one-time U.S. federal tax on the deemed repatriation of unremitted earnings indefinitely reinvested abroad, which did not have a material impact on the company's financial results. The indefinite reinvestment assertion continues to apply for the purpose of determining deferred tax liabilities for U.S. state and foreign withholding tax purposes.

U.S. state and foreign withholding taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled approximately \$57,300 at December 31, 2017. This amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of state and foreign taxes that might be payable on the possible remittance of earnings that are intended to be reinvested indefinitely. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

Uncertain Income Tax Positions The company recognizes a tax benefit in the financial statements for an uncertain tax position only if management's assessment is that the position is "more likely than not" (i.e., a likelihood greater than 50 percent) to be allowed by the tax jurisdiction based solely on the technical merits of the position. The term "tax position" in the accounting standards for income taxes refers to a position in a previously filed tax return or a position expected to be taken in a future tax return that is reflected in measuring current or deferred income tax assets and liabilities for interim or annual periods.

The following table indicates the changes to the company's unrecognized tax benefits for the years ended December 31, 2017, 2016 and 2015. The term "unrecognized tax benefits" in the accounting standards for income taxes refers to the differences between a tax position taken or expected to be taken in a tax return and the benefit measured and recognized in the financial statements. Interest and penalties are not included.

	2017	2016	2015
Balance at January 1	\$ 3,031	\$ 3,042	\$ 3,552
Foreign currency effects	43	1	(27)
Additions based on tax positions taken in current year	1,853	245	154
Additions for tax positions taken in prior years	1,166	181	218
Reductions for tax positions taken in prior years	(90)	(390)	(678)
Settlements with taxing authorities in current year	(1,173)	(36)	(5)
Reductions as a result of a lapse of the applicable statute of limitations	(2)	(12)	(172)
Balance at December 31	\$ 4,828	\$ 3,031	\$ 3,042

The increase in unrecognized tax benefits between December 31, 2016 and December 31, 2017 was primarily due to foreign tax credits associated with the deemed repatriation. The increase in unrecognized tax benefits related to these foreign tax credits had no impact on the effective tax rate since the change to the deferred tax asset was fully offset with a change to the valuation allowance. The resolution of numerous issues with various tax jurisdictions during the year also impacted the movement from December 31, 2016 and December 31, 2017.

Approximately 81 percent of the \$4,828 of unrecognized tax benefits at December 31, 2017, would have an impact on the effective tax rate if subsequently recognized. Certain of these unrecognized tax benefits relate to tax carryforwards that may require a full valuation allowance at the time of any such recognition.

Tax positions for Chevron and its subsidiaries and affiliates are subject to income tax audits by many tax jurisdictions throughout the world. For the company's major tax jurisdictions, examinations of tax returns for certain prior tax years had not been completed as of December 31, 2017. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2011, Nigeria – 2000, Australia – 2006, Angola – 2016 and Kazakhstan – 2007.

The company engages in ongoing discussions with tax authorities regarding the resolution of tax matters in the various jurisdictions. Both the outcome of these tax matters and the timing of resolution and/or closure of the tax audits are highly uncertain. However, it is reasonably possible that developments on tax matters in certain tax jurisdictions may result in significant increases or decreases in the company's total unrecognized tax benefits within the next 12 months. Given the number of years that still remain subject to examination and the number of matters being examined in the various tax jurisdictions, the company is unable to estimate the range of possible adjustments to the balance of unrecognized tax benefits.

On April 21, 2017, an adverse decision was issued by the full Federal Court on Australia regarding the interest rate to be applied on certain Chevron intercompany loans. On August 14, 2017, an agreement was reached with the Australian Taxation Office to settle this dispute. Management believes the agreed terms to be a reasonable resolution of the dispute, which did not have a material impact on the 2017 results of the company.

On the Consolidated Statement of Income, the company reports interest and penalties related to liabilities for uncertain tax positions as "Income tax expense." As of December 31, 2017, accruals of \$178 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of \$424 as of year-end 2016. Income tax expense (benefit) associated with interest and penalties was \$(161), \$38 and \$195 in 2017, 2016 and 2015, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2017	2016	2015
United States			
Excise and similar taxes on products and merchandise	\$ 4,398	\$ 4,335	\$ 4,426
Import duties and other levies	11	9	4
Property and other miscellaneous taxes	1,824	1,680	1,367
Payroll taxes	241	252	270
Taxes on production	206	159	157
Total United States	6,680	6,435	6,224
International			
Excise and similar taxes on products and merchandise	2,791	2,570	2,933
Import duties and other levies	45	33	40
Property and other miscellaneous taxes	2,563	2,379	2,548
Payroll taxes	137	145	161
Taxes on production	115	106	124
Total International	5,651	5,233	5,806
Total taxes other than on income	\$ 12,331	\$ 11,668	\$ 12,030

Note 19**Short-Term Debt**

	At December 31	
	2017	2016
Commercial paper ¹	\$ 5,379	\$ 10,410
Notes payable to banks and others with originating terms of one year or less	—	50
Current maturities of long-term debt ²	6,720	6,253
Current maturities of long-term capital leases	15	14
Redeemable long-term obligations		
Long-term debt	3,078	3,113
Capital leases	—	—
Subtotal	15,192	19,840
Reclassified to long-term debt	(10,000)	(9,000)
Total short-term debt	\$ 5,192	\$ 10,840

¹ Weighted-average interest rates at December 31, 2017 and 2016, were 1.30 percent and 0.74 percent, respectively.

² Net of unamortized discounts and issuance costs.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date.

The company may periodically enter into interest rate swaps on a portion of its short-term debt. At December 31, 2017, the company had no interest rate swaps on short-term debt.

At December 31, 2017, the company had \$10,000 in committed credit facilities with various major banks that enable the refinancing of short-term obligations on a long-term basis. The credit facilities consist of a 364-day facility which enables borrowing of up to \$9,575 and allows the company to convert any amounts outstanding into a term loan for a period of up to one year, and a \$425 five-year facility expiring in December 2020. These facilities support commercial paper borrowing and can also be used for general corporate purposes. The company's practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company's strong credit rating. No borrowings were outstanding under these facilities at December 31, 2017.

The company classified \$10,000 and \$9,000 of short-term debt as long-term at December 31, 2017 and 2016, respectively. Settlement of these obligations is not expected to require the use of working capital within one year, and the company has both the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Note 20**Long-Term Debt**

Total long-term debt, excluding capital leases, at December 31, 2017, was \$33,477. The company's long-term debt outstanding at year-end 2017 and 2016 was as follows:

	At December 31	
	2017	2016
	Principal	Principal
3.191% notes due 2023	\$ 2,250	\$ 2,250
2.954% notes due 2026	2,250	2,250
1.718% notes due 2018	2,000	2,000
2.355% notes due 2022	2,000	2,000
1.365% notes due 2018	1,750	1,750
1.961% notes due 2020	1,750	1,750
Floating rate notes due 2018 (1.833%) ¹	1,650	1,650
4.950% notes due 2019	1,500	1,500
1.561% notes due 2019	1,350	1,350
2.100% notes due 2021	1,350	1,350
1.790% notes due 2018	1,250	1,250
2.419% notes due 2020	1,250	1,250
2.427% notes due 2020	1,000	1,000
2.895% notes due 2024	1,000	—
Floating rate notes due 2019 (1.684%) ¹	850	400
2.193% notes due 2019	750	750
2.566% notes due 2023	750	750
3.326% notes due 2025	750	750
2.498% notes due 2022	700	—
2.411% notes due 2022	700	700
Floating rate notes due 2021 (2.109%) ¹	650	650
Floating rate notes due 2022 (1.994%) ¹	650	350
1.991% notes due 2020	600	—
1.686% notes due 2019	550	—
Floating rate notes due 2020 (1.697%) ²	400	—
8.625% debentures due 2032	147	147
8.625% debentures due 2031	108	108
8.000% debentures due 2032	75	75
Amortizing bank loan due 2018 (2.179%) ²	72	178
9.750% debentures due 2020	54	54
8.875% debentures due 2021	40	40
Medium-term notes, maturing from 2021 to 2038 (6.283%) ¹	38	38
Floating rate notes due 2017	—	2,050
1.104% notes due 2017	—	2,000
1.345% notes due 2017	—	1,100
1.344% notes due 2017	—	1,000
Total including debt due within one year	30,234	32,490
Debt due within one year	(6,722)	(6,256)
Reclassified from short-term debt	10,000	9,000
Unamortized discounts and debt issuance costs	(35)	(41)
Total long-term debt	\$ 33,477	\$ 35,193

¹ Weighted-average interest rate at December 31, 2017.

² Interest rate at December 31, 2017.

Chevron has an automatic shelf registration statement that expires in August 2018. This registration statement is for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

Long-term debt with a principal balance of \$30,234 matures as follows: 2018 – \$6,722; 2019 – \$5,000; 2020 – \$5,054; 2021 – \$2,054; 2022 – \$4,050; and after 2022 – \$7,354.

The company completed a bond issuance of \$4,000 in first quarter 2017.

See Note 10, beginning on page 46, for information concerning the fair value of the company's long-term debt.

Note 21**Accounting for Suspended Exploratory Wells**

The company continues to capitalize exploratory well costs after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well, and (b) the business unit is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if the company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2017:

	2017	2016	2015
Beginning balance at January 1	\$ 3,540	\$ 3,312	\$ 4,195
Additions to capitalized exploratory well costs pending the determination of proved reserves	323	465	869
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(113)	(119)	(164)
Capitalized exploratory well costs charged to expense	(39)	(118)	(1,397)
Other reductions*	(9)	—	(191)
Ending balance at December 31	\$ 3,702	\$ 3,540	\$ 3,312

* Represents property sales.

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

	At December 31		
	2017	2016	2015
Exploratory well costs capitalized for a period of one year or less	\$ 307	\$ 445	\$ 489
Exploratory well costs capitalized for a period greater than one year	3,395	3,095	2,823
Balance at December 31	\$ 3,702	\$ 3,540	\$ 3,312
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	32	35	39

* Certain projects have multiple wells or fields or both.

Of the \$3,395 of exploratory well costs capitalized for more than one year at December 31, 2017, \$2,257 (17 projects) is related to projects that had drilling activities underway or firmly planned for the near future. The \$1,138 balance is related to 15 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not underway or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the \$1,138 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) \$190 (two projects) – undergoing front-end engineering and design with final investment decision expected within four years; (b) \$99 (one project) – development concept under review by government; (c) \$826 (seven projects) – development alternatives under review; (d) \$23 (five projects) – miscellaneous activities for projects with smaller amounts suspended. While progress was being made on all 32 projects, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations associated with the projects. More than half of these decisions are expected to occur in the next five years.

The \$3,395 of suspended well costs capitalized for a period greater than one year as of December 31, 2017, represents 158 exploratory wells in 32 projects. The tables below contain the aging of these costs on a well and project basis:

<i>Aging based on drilling completion date of individual wells:</i>		Amount	Number of wells
1998-2006	\$	318	29
2007-2011		879	50
2012-2016		2,198	79
Total	\$	3,395	158

<i>Aging based on drilling completion date of last suspended well in project:</i>		Amount	Number of projects
2003-2009	\$	344	5
2010-2013		367	6
2014-2017		2,684	21
Total	\$	3,395	32

Note 22

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2017, 2016 and 2015 was \$137 (\$89 after tax), \$271 (\$176 after tax) and \$312 (\$203 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance shares and restricted stock units was \$231 (\$150 after tax), \$371 (\$241 after tax) and \$32 (\$21 after tax) for 2017, 2016 and 2015, respectively. No significant stock-based compensation cost was capitalized at December 31, 2017, or December 31, 2016.

Cash received in payment for option exercises under all share-based payment arrangements for 2017, 2016 and 2015 was \$1,100, \$647 and \$195, respectively. Actual tax benefits realized for the tax deductions from option exercises were \$48, \$21 and \$17 for 2017, 2016 and 2015, respectively.

Cash paid to settle performance shares and stock appreciation rights was \$187, \$82 and \$104 for 2017, 2016 and 2015, respectively.

Awards under the Chevron Long-Term Incentive Plan (LTIP) may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares and nonstock grants. From April 2004 through May 2023, no more than 260 million shares may be issued under the LTIP. For awards issued on or after May 29, 2013, no more than 50 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient. For the major types of awards issued before January 1, 2017, the contractual terms vary between three years for the performance shares and restricted stock units, and 10 years for the stock options and stock appreciation rights. For awards issued after January 1, 2017, contractual terms vary between three years for the performance shares and special restricted stock units, 5 years for standard restricted stock units and 10 years for the stock options and stock appreciation rights. Forfeitures for performance shares, restricted stock units, and stock appreciation rights are recognized as they occur. Forfeitures for stock options are estimated using historical forfeiture data dating back to 1990.

The fair market values of stock options and stock appreciation rights granted in 2017, 2016 and 2015 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2017	2016	2015
Expected term in years ¹	6.3	6.3	6.1
Volatility ²	21.7 %	21.7 %	21.9 %
Risk-free interest rate based on zero coupon U.S. treasury note	2.2 %	1.6 %	1.4 %
Dividend yield	4.2 %	4.5 %	3.6 %
Weighted-average fair value per option granted	\$ 15.31	\$ 9.53	\$ 13.89

¹ Expected term is based on historical exercise and postvesting cancellation data.

² Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

A summary of option activity during 2017 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Averaged Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at January 1, 2017	112,275	\$ 94.99		
Granted	5,887	\$ 117.16		
Exercised	(13,110)	\$ 84.86		
Forfeited	(1,277)	\$ 105.02		
Outstanding at December 31, 2017	103,765	\$ 97.40	5.63	\$ 2,883
Exercisable at December 31, 2017	78,120	\$ 98.54	4.82	\$ 2,082

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2017, 2016 and 2015 was \$407, \$240 and \$120, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2017, there was \$88 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted under the plan. That cost is expected to be recognized over a weighted-average period of 1.4 years.

At January 1, 2017, the number of LTIP performance shares outstanding was equivalent to 2,393,428 shares. During 2017, 1,623,526 performance shares were granted, 708,192 shares vested with cash proceeds distributed to recipients and 217,969 shares were forfeited. At December 31, 2017, performance shares outstanding were 3,090,793. The fair value of the liability recorded for these instruments was \$340, and was measured using the Monte Carlo simulation method.

At January 1, 2017, the number of restricted stock units outstanding was equivalent to 557,415 shares. During 2017, 892,991 restricted stock units were granted, 96,210 units vested with cash proceeds distributed to recipients and 117,696 units were forfeited. At December 31, 2017, restricted stock units outstanding were 1,236,500. The fair value of the liability recorded for the vested portion of these instruments was \$98, valued at the stock price as of December 31, 2017. In addition, outstanding stock appreciation rights that were granted under LTIP totaled approximately 4.6 million equivalent shares as of December 31, 2017. The fair value of the liability recorded for the vested portion of these instruments was \$115.

Note 23

Employee Benefit Plans

The company has defined benefit pension plans for many employees. The company typically prefunds defined benefit plans as required by local regulations or in certain situations where prefunding provides economic advantages. In the United States, all qualified plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund U.S. nonqualified pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be less economic and investment returns may be less attractive than the company's other investment alternatives.

The company also sponsors other postretirement benefit (OPEB) plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and retirees share the costs. Beginning in 2017, medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is provided through a third-party private exchange. The increase to the pre-Medicare company contribution for retiree medical coverage is limited to no more than 4 percent each year. Certain life insurance benefits are paid by the company.

The company recognizes the overfunded or underfunded status of each of its defined benefit pension and OPEB plans as an asset or liability on the Consolidated Balance Sheet.

The funded status of the company's pension and OPEB plans for 2017 and 2016 follows:

	Pension Benefits				Other Benefits	
	2017		2016		2017	2016
	U.S.	Int'l.	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	\$ 13,271	\$ 5,169	\$ 13,563	\$ 5,336	\$ 2,549	\$ 3,324
Service cost	489	151	494	159	32	60
Interest cost	366	219	377	261	95	128
Plan participants' contributions	—	4	—	5	78	148
Plan amendments	—	1	—	—	—	(345)
Actuarial (gain) loss	1,168	(37)	903	426	266	(437)
Foreign currency exchange rate changes	—	374	—	(524)	10	8
Benefits paid	(1,714)	(310)	(2,066)	(494)	(229)	(337)
Divestitures	—	(31)	—	—	(13)	—
Benefit obligation at December 31	13,580	5,540	13,271	5,169	2,788	2,549
Change in Plan Assets						
Fair value of plan assets at January 1	9,550	4,174	10,274	4,109	—	—
Actual return on plan assets	1,384	319	936	642	—	—
Foreign currency exchange rate changes	—	358	—	(552)	—	—
Employer contributions	728	252	406	464	151	189
Plan participants' contributions	—	4	—	5	78	148
Benefits paid	(1,714)	(310)	(2,066)	(494)	(229)	(337)
Divestitures	—	(31)	—	—	—	—
Fair value of plan assets at December 31	9,948	4,766	9,550	4,174	—	—
Funded status at December 31	\$ (3,632)	\$ (774)	\$ (3,721)	\$ (995)	\$ (2,788)	\$ (2,549)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and OPEB plans at December 31, 2017 and 2016, include:

	Pension Benefits				Other Benefits	
	2017		2016		2017	2016
	U.S.	Int'l.	U.S.	Int'l.		
Deferred charges and other assets	\$ 21	\$ 448	\$ 16	\$ 199	\$ —	\$ —
Accrued liabilities	(188)	(100)	(222)	(75)	(174)	(163)
Noncurrent employee benefit plans	(3,465)	(1,122)	(3,515)	(1,119)	(2,614)	(2,386)
Net amount recognized at December 31	\$ (3,632)	\$ (774)	\$ (3,721)	\$ (995)	\$ (2,788)	\$ (2,549)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were \$5,286 and \$5,511 at the end of 2017 and 2016, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2017		2016		2017	2016
	U.S.	Int'l.	U.S.	Int'l.		
Net actuarial loss	\$ 4,258	\$ 1,005	\$ 4,653	\$ 1,145	\$ 207	\$ (82)
Prior service (credit) costs	9	94	4	106	(287)	(315)
Total recognized at December 31	\$ 4,267	\$ 1,099	\$ 4,657	\$ 1,251	\$ (80)	\$ (397)

The accumulated benefit obligations for all U.S. and international pension plans were \$12,194 and \$5,009, respectively, at December 31, 2017, and \$11,954 and \$4,676, respectively, at December 31, 2016.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2017 and 2016, was:

	Pension Benefits			
	2017		2016	
	U.S.	Int'l.	U.S.	Int'l.
Projected benefit obligations	\$ 13,514	\$ 1,590	\$ 13,208	\$ 1,449
Accumulated benefit obligations	12,129	1,326	11,891	1,258
Fair value of plan assets	9,862	413	9,471	287

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2017, 2016 and 2015 are shown in the table below:

	Pension Benefits						Other Benefits		
	2017		2016		2015		2017	2016	2015
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Net Periodic Benefit Cost									
Service cost	\$ 489	\$ 151	\$ 494	\$ 159	\$ 538	\$ 185	\$ 32	\$ 60	\$ 72
Interest cost	366	219	377	261	502	277	95	128	151
Expected return on plan assets	(597)	(239)	(723)	(243)	(783)	(262)	—	—	—
Amortization of prior service costs (credits)	(5)	13	(9)	14	(8)	22	(28)	14	14
Recognized actuarial losses	340	44	335	47	356	78	(5)	19	34
Settlement losses	436	2	511	6	320	6	—	—	—
Curtailed losses (gains)	—	—	—	—	—	(14)	—	—	—
Total net periodic benefit cost	1,029	190	985	244	925	292	94	221	271
Changes Recognized in Comprehensive Income									
Net actuarial (gain) loss during period	381	(94)	690	55	513	(260)	284	(430)	(362)
Amortization of actuarial loss	(776)	(46)	(846)	(53)	(676)	(84)	5	(19)	(34)
Prior service (credits) costs during period	—	1	—	—	—	(6)	—	(345)	—
Amortization of prior service (costs) credits	5	(13)	9	(14)	8	(24)	28	(14)	(14)
Total changes recognized in other comprehensive income	(390)	(152)	(147)	(12)	(155)	(374)	317	(808)	(410)
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	\$ 639	\$ 38	\$ 838	\$ 232	\$ 770	\$ (82)	\$ 411	\$ (587)	\$ (139)

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2017, for the company's U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 10, 12 and 15 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive

benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2018, the company estimates actuarial losses of \$303, \$30 and \$15 will be amortized from “Accumulated other comprehensive loss” for U.S. pension, international pension and OPEB plans, respectively. In addition, the company estimates an additional \$334 will be recognized from “Accumulated other comprehensive loss” during 2018 related to lump-sum settlement costs from the main U.S. pension plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded in “Accumulated other comprehensive loss” at December 31, 2017, was approximately 5 and 9 years for U.S. and international pension plans, respectively, and 9 years for OPEB plans. During 2018, the company estimates prior service (credits) costs of \$2, \$11 and \$(28) will be amortized from “Accumulated other comprehensive loss” for U.S. pension, international pension and OPEB plans, respectively.

Assumptions The following weighted-average assumptions were used to determine benefit obligations and net periodic benefit costs for years ended December 31:

	Pension Benefits						Other Benefits		
	2017		2016		2015		2017	2016	2015
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Assumptions used to determine benefit obligations:									
Discount rate	3.5%	3.9%	3.9%	4.3%	4.0%	5.3%	3.8%	4.3%	4.6%
Rate of compensation increase	4.5%	4.0%	4.5%	4.5%	4.5%	4.8%	N/A	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate for service cost	4.2%	4.3%	4.4%	5.3%	3.7%	5.0%	4.6%	4.9%	4.3%
Discount rate for interest cost	3.0%	4.3%	3.0%	5.3%	3.7%	5.0%	3.8%	4.0%	4.3%
Expected return on plan assets	6.8%	5.5%	7.3%	6.3%	7.5%	6.3%	N/A	N/A	N/A
Rate of compensation increase	4.5%	4.5%	4.5%	4.8%	4.5%	5.1%	N/A	N/A	N/A

Expected Return on Plan Assets The company’s estimated long-term rates of return on pension assets are driven primarily by actual historical asset-class returns, an assessment of expected future performance, advice from external actuarial firms and the incorporation of specific asset-class risk factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the company’s estimated long-term rates of return are consistent with these studies.

For 2017, the company used an expected long-term rate of return of 6.75 percent for U.S. pension plan assets, which account for 68 percent of the company’s pension plan assets. In 2016, the company used a long-term rate of return of 7.25 percent for this plan, and in 2015, 7.50 percent.

The market-related value of assets of the main U.S. pension plan used in the determination of pension expense was based on the market values in the three months preceding the year-end measurement date. Management considers the three-month time period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of year-end is used in calculating the pension expense.

Discount Rate The discount rate assumptions used to determine the U.S. and international pension and OPEB plan obligations and expense reflect the rate at which benefits could be effectively settled, and are equal to the equivalent single rate resulting from yield curve analysis. This analysis considered the projected benefit payments specific to the company’s plans and the yields on high-quality bonds. The projected cash flows were discounted to the valuation date using the yield curve for the main U.S. pension and OPEB plans. The effective discount rates derived from this analysis at the end of 2017 were 3.5 percent for the main U.S. pension plan and 3.6 percent for the main U.S. OPEB plan. The discount rates for these plans at the end of 2016 were 3.9 and 4.1 percent, respectively, while in 2015 they were 4.0 and 4.5 percent for these plans, respectively.

Beginning with the fiscal year ended December 31, 2016, the company changed the method used to estimate the service and interest cost associated with the company’s main U.S. pension and OPEB plans. Under the new method, these costs are estimated by applying spot rates along the yield curve to the relevant projected cash flows. In prior years, the service and interest costs were estimated utilizing a single weighted-average discount rate derived from the yield curve used to measure the defined benefit obligations at the beginning of the year.

Other Benefit Assumptions Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. For the measurement of accumulated postretirement benefit obligation at December 31, 2017, for the main U.S. OPEB plan, the assumed health care cost-trend rates start with 7.4 percent in 2018 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2016, the assumed health care cost-trend rates

started with 6.9 percent in 2017 and gradually declined to 4.5 percent for 2025 and beyond. The annual increase to the company's pre-Medicare medical contributions for the main U.S. plan upon retirement is capped at 4 percent. A 1-percentage-point change in the assumed health care cost-trend rates would have the following effects on worldwide plans:

	1 Percent Increase		1 Percent Decrease	
Effect on total service and interest cost components	\$	12	\$	(10)
Effect on postretirement benefit obligation	\$	188	\$	(155)

Plan Assets and Investment Strategy

The fair value measurements of the company's pension plans for 2017 and 2016 are below:

	U.S.					Int'l.				
	Total	Level 1	Level 2	Level 3	NAV ¹	Total	Level 1	Level 2	Level 3	NAV ¹
At December 31, 2016										
Equities										
U.S. ²	\$ 1,217	\$ 1,217	\$ —	\$ —	\$ —	\$ 565	\$ 564	\$ 1	\$ —	\$ —
International	1,832	1,822	10	—	—	576	576	—	—	—
Collective Trusts/Mutual Funds ³	1,132	24	—	—	1,108	196	8	2	—	186
Fixed Income										
Government ⁴	222	—	222	—	—	286	51	235	—	—
Corporate ⁴	1,356	—	1,356	—	—	509	22	468	19	—
Bank Loans	118	—	107	11	—	—	—	—	—	—
Mortgage/Asset Backed	1	—	1	—	—	10	—	10	—	—
Collective Trusts/Mutual Funds ^{3,4}	1,031	—	—	—	1,031	1,278	—	17	—	1,261
Mixed Funds ⁵	—	—	—	—	—	72	2	70	—	—
Real Estate ⁶	1,367	—	—	—	1,367	331	—	—	60	271
Alternative Investments ⁷	955	—	—	—	955	—	—	—	—	—
Cash and Cash Equivalents	252	243	9	—	—	331	325	6	—	—
Other ⁸	67	(9)	25	42	9	20	—	18	2	—
Total at December 31, 2016	\$ 9,550	\$ 3,297	\$ 1,730	\$ 53	\$ 4,470	\$ 4,174	\$ 1,548	\$ 827	\$ 81	\$ 1,718
At December 31, 2017										
Equities										
U.S. ²	\$ 1,331	\$ 1,331	\$ —	\$ —	\$ —	\$ 652	\$ 651	\$ 1	\$ —	\$ —
International	2,060	2,057	3	—	—	691	691	—	—	—
Collective Trusts/Mutual Funds ³	1,089	22	—	—	1,067	204	19	4	—	181
Fixed Income										
Government	274	—	274	—	—	296	77	219	—	—
Corporate	1,492	—	1,492	—	—	593	—	563	30	—
Bank Loans	117	—	106	11	—	—	—	—	—	—
Mortgage/Asset Backed	1	—	1	—	—	8	—	8	—	—
Collective Trusts/Mutual Funds ³	1,130	—	—	—	1,130	1,481	—	16	—	1,465
Mixed Funds ⁵	—	—	—	—	—	80	1	79	—	—
Real Estate ⁶	1,096	—	—	—	1,096	376	—	—	56	320
Alternative Investments ⁷	1,022	—	—	—	1,022	—	—	—	—	—
Cash and Cash Equivalents	260	255	5	—	—	366	362	4	—	—
Other ⁸	76	(2)	28	43	7	19	(2)	18	3	—
Total at December 31, 2017	\$ 9,948	\$ 3,663	\$ 1,909	\$ 54	\$ 4,322	\$ 4,766	\$ 1,799	\$ 912	\$ 89	\$ 1,966

¹ 2016 has been adjusted to conform to the 2017 presentation of investments measured at Net Asset Value (NAV).

² U.S. equities include investments in the company's common stock in the amount of \$12 at December 31, 2017, and \$12 at December 31, 2016.

³ Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly unit trust and index funds.

⁴ Certain International Fixed Income investments previously disclosed as Government or Corporate have been reclassified to Collective Trusts/Mutual Funds to conform to the 2017 presentation.

⁵ Mixed funds are composed of funds that invest in both equity and fixed-income instruments in order to diversify and lower risk.

⁶ The year-end valuations of the U.S. real estate assets are based on third-party appraisals that occur at least once a year for each property in the portfolio.

⁷ Alternative investments focus on market-neutral strategies that have a low expected correlation to traditional asset classes.

⁸ The "Other" asset class includes net payables for securities purchased but not yet settled (Level 1); dividends and interest- and tax-related receivables (Level 2); insurance contracts (Level 3); and investments in private-equity limited partnerships (NAV).

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

	Fixed Income					Total
	Corporate	Bank Loans	Real Estate	Other		
Total at December 31, 2015¹	\$ 25	\$ —	\$ 97	\$ 43	\$ 165	
Actual Return on Plan Assets:						
Assets held at the reporting date	1	—	(33)	—	(32)	
Assets sold during the period	—	—	1	—	1	
Purchases, Sales and Settlements	(7)	11	(5)	1	—	
Transfers in and/or out of Level 3	—	—	—	—	—	
Total at December 31, 2016¹	\$ 19	\$ 11	\$ 60	\$ 44	\$ 134	
Actual Return on Plan Assets:						
Assets held at the reporting date	1	—	1	—	2	
Assets sold during the period	—	—	—	—	—	
Purchases, Sales and Settlements	10	3	(5)	2	10	
Transfers in and/or out of Level 3	—	(3)	—	—	(3)	
Total at December 31, 2017	\$ 30	\$ 11	\$ 56	\$ 46	\$ 143	

¹ 2015 and 2016 have been adjusted to conform to the 2017 presentation.

The primary investment objectives of the pension plans are to achieve the highest rate of total return within prudent levels of risk and liquidity, to diversify and mitigate potential downside risk associated with the investments, and to provide adequate liquidity for benefit payments and portfolio management.

The company's U.S. and U.K. pension plans comprise 90 percent of the total pension assets. Both the U.S. and U.K. plans have an Investment Committee that regularly meets during the year to review the asset holdings and their returns. To assess the plans' investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the company's Benefit Plan Investment Committee has established the following approved asset allocation ranges: Equities 30–60 percent, Fixed Income and Cash 20–65 percent, Real Estate 0–15 percent, and Alternative Investments 0–15 percent. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines: Equities 30–50 percent, Fixed Income and Cash 35–70 percent, and Real Estate 5–15 percent. The other significant international pension plans also have established maximum and minimum asset allocation ranges that vary by plan. Actual asset allocation within approved ranges is based on a variety of factors, including market conditions and illiquidity constraints. To mitigate concentration and other risks, assets are invested across multiple asset classes with active investment managers and passive index funds.

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2017, the company contributed \$728 and \$252 to its U.S. and international pension plans, respectively. In 2018, the company expects contributions to be approximately \$700 to its U.S. plans and \$250 to its international pension plans. Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments, tax law changes and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying OPEB benefits of approximately \$174 in 2018; \$151 was paid in 2017.

The following benefit payments, which include estimated future service, are expected to be paid by the company in the next 10 years:

	Pension Benefits		Other Benefits
	U.S.	Int'l.	
2018	\$ 1,465	\$ 387	\$ 174
2019	\$ 1,331	\$ 279	\$ 175
2020	\$ 1,296	\$ 289	\$ 175
2021	\$ 1,261	\$ 277	\$ 175
2022	\$ 1,234	\$ 290	\$ 174
2023-2027	\$ 5,487	\$ 1,609	\$ 850

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP). Compensation expense for the ESIP totaled \$316, \$281 and \$316 in 2017, 2016 and 2015, respectively.

Benefit Plan Trusts Prior to its acquisition by Chevron, Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2017, the trust contained 14.2 million shares of Chevron treasury stock. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The company intends to continue to pay its obligations under the benefit plans. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Prior to its acquisition by Chevron, Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2017 and 2016, trust assets of \$35 and \$35, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans The Chevron Incentive Plan is an annual cash bonus plan for eligible employees that links awards to corporate, business unit and individual performance in the prior year. Charges to expense for cash bonuses were \$936, \$662 and \$690 in 2017, 2016 and 2015, respectively. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 22, beginning on page 63.

Note 24

Properties, Plant and Equipment¹

	At December 31									Year ended December 31		
	Gross Investment at Cost			Net Investment			Additions at Cost ²			Depreciation Expense ³		
	2017	2016	2015	2017	2016	2015	2017	2016	2015	2017	2016	2015
Upstream												
United States	\$ 84,602	\$ 83,929	\$ 93,848	\$ 38,722	\$ 39,710	\$ 43,125	\$ 4,995	\$ 4,432	\$ 6,586	\$ 5,527	\$ 6,576	\$ 8,545
International	224,211	214,557	208,395	123,191	125,502	127,459	7,934	12,084	19,993	12,096	11,247	10,803
Total Upstream	308,813	298,486	302,243	161,913	165,212	170,584	12,929	16,516	26,579	17,623	17,823	19,348
Downstream												
United States	23,598	22,795	23,202	10,346	10,196	10,807	907	528	696	753	956	878
International	7,094	9,350	9,177	3,074	4,094	4,090	306	375	365	282	332	355
Total Downstream	30,692	32,145	32,379	13,420	14,290	14,897	1,213	903	1,061	1,035	1,288	1,233
All Other												
United States	4,798	5,263	5,500	2,341	2,635	2,859	218	198	357	677	328	439
International	182	183	155	38	49	56	4	6	5	14	18	17
Total All Other	4,980	5,446	5,655	2,379	2,684	2,915	222	204	362	691	346	456
Total United States	112,998	111,987	122,550	51,409	52,541	56,791	6,120	5,158	7,639	6,957	7,860	9,862
Total International	231,487	224,090	217,727	126,303	129,645	131,605	8,244	12,465	20,363	12,392	11,597	11,175
Total	\$ 344,485	\$ 336,077	\$340,277	\$ 177,712	\$ 182,186	\$ 188,396	\$ 14,364	\$ 17,623	\$ 28,002	\$ 19,349	\$ 19,457	\$ 21,037

¹ Other than the United States, Australia and Nigeria, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2017. Australia had PP&E of \$55,514, \$53,962 and \$49,205 in 2017, 2016, and 2015, respectively. Nigeria had PP&E of \$17,076, \$17,922 and \$18,773 for 2017, 2016 and 2015, respectively.

² Net of dry hole expense related to prior years' expenditures of \$42, \$175 and \$1,573 in 2017, 2016 and 2015, respectively.

³ Depreciation expense includes accretion expense of \$668, \$749 and \$715 in 2017, 2016 and 2015, respectively, and impairments of \$1,021, \$3,186 and \$4,066 in 2017, 2016 and 2015, respectively.

Note 25

Other Contingencies and Commitments

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 18, beginning on page 57, for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return.

As discussed in Note 18, beginning on page 57, the company received an adverse decision on April 21, 2017, regarding the interest rate to be applied on certain Chevron intercompany loans. On August 14, 2017, an agreement was reached with the Australian Taxation Office to settle this dispute. Management believes the agreed terms to be a reasonable resolution of the dispute, which did not have a material impact on the 2017 results of the company.

Settlement of open tax years, as well as other tax issues in countries where the company conducts its businesses, are not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees The company has two guarantees to equity affiliates totaling \$1,082. Of this amount, \$712 is associated with a financing arrangement with an equity affiliate. Over the approximate 4-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of \$370 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 10-year remaining term of this guarantee, the maximum guarantee amount will be reduced as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of amounts paid under the guarantee. Chevron has recorded no liability for either guarantee.

Indemnifications In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. The acquirer of those assets shared in certain environmental remediation costs up to a maximum obligation of \$200, which had been reached at December 31, 2009. Under the indemnification agreement, after reaching the \$200 obligation, Chevron is solely responsible until April 2022, when the indemnification expires. The environmental conditions or events that are subject to these indemnities must have arisen prior to the sale of the assets in 1997.

Although the company has provided for known obligations under this indemnity that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2018 – \$1,402; 2019 – \$1,367; 2020 – \$1,027; 2021 – \$920; 2022 – \$555; 2023 and after – \$2,566. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$1,300 in 2017, \$1,300 in 2016 and \$1,900 in 2015.

Environmental The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various operating, closed and divested sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, chemical plants, marketing facilities, crude oil fields, and mining sites.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, it is likely that the company will continue to incur additional liabilities. The amount of additional future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. These future costs may be material to results of operations in the period in which they are recognized, but the company does not expect these costs will have a material effect on its consolidated financial position or liquidity.

Chevron's environmental reserve as of December 31, 2017, was \$1,429. Included in this balance was \$269 related to remediation activities at approximately 146 sites for which the company had been identified as a potentially responsible party under the provisions of the federal Superfund law or analogous state laws which provide for joint and several liability for all responsible parties. Any future actions by regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2017 environmental reserves balance of \$1,160, \$781 is related to the company's U.S. downstream operations, \$38 to its international downstream operations, \$340 to upstream operations and \$1 to other businesses. Liabilities at all sites were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state and local regulations. No single remediation site at year-end 2017 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

Refer to Note 26 on page 71 for a discussion of the company's asset retirement obligations.

Other Contingencies Chevron receives claims from and submits claims to customers; trading partners; joint venture partners; U.S. federal, state and local regulatory bodies; governments; contractors; insurers; suppliers; and individuals. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve, and may result in gains or losses in future periods.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in significant gains or losses in future periods.

Note 26

Asset Retirement Obligations

The company records the fair value of a liability for an asset retirement obligation (ARO) as an asset and liability when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional, even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company's control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. Recognition of the ARO includes: (1) the present value of a liability and offsetting asset, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

AROs are primarily recorded for the company's crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire downstream long-lived assets have been recognized, as indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2017, 2016 and 2015:

	2017	2016	2015
Balance at January 1	\$ 14,243	\$ 15,642	\$ 15,053
Liabilities incurred	684	204	51
Liabilities settled	(1,721)	(1,658)	(981)
Accretion expense	668	749	715
Revisions in estimated cash flows	340	(694)	804
Balance at December 31	\$ 14,214	\$ 14,243	\$ 15,642

In the table above, the amount associated with "Revisions in estimated cash flows" in 2017 reflects increased cost estimates to abandon wells, equipment and facilities. The long-term portion of the \$14,214 balance at the end of 2017 was \$13,228.

Note 27

Other Financial Information

Earnings in 2017 included after-tax gains of approximately \$1,800 relating to the sale of certain properties. Of this amount, approximately \$850 and \$950 related to downstream and upstream, respectively. Earnings in 2016 included after-tax gains of approximately \$800 relating to the sale of certain properties, of which approximately \$600 and \$200 related to downstream and upstream assets, respectively. Earnings in 2017 included after-tax charges of approximately \$900 for impairments and other asset write-offs related to upstream. Earnings in 2016 included after-tax charges of approximately \$2,900 for impairments and other asset write-offs related to upstream, and \$110 related to downstream.

Other financial information is as follows:

	Year ended December 31		
	2017	2016	2015
Total financing interest and debt costs	\$ 902	\$ 753	\$ 495
Less: Capitalized interest	595	552	495
Interest and debt expense	\$ 307	\$ 201	\$ —
Research and development expenses	\$ 433	\$ 476	\$ 601
Excess of replacement cost over the carrying value of inventories (LIFO method)	\$ 3,937	\$ 2,942	\$ 3,745
LIFO losses on inventory drawdowns included in earnings	\$ (5)	\$ (88)	\$ (65)
Foreign currency effects*	\$ (446)	\$ 58	\$ 769

* Includes \$(45), \$1 and \$344 in 2017, 2016 and 2015, respectively, for the company's share of equity affiliates' foreign currency effects.

The company has \$4,531 in goodwill on the Consolidated Balance Sheet, all of which is in the upstream segment and related primarily to the 2005 acquisition of Unocal. The company tested this goodwill for impairment during 2017, and no impairment was required.

Five-Year Financial Summary
Unaudited

<i>Millions of dollars, except per-share amounts</i>	2017	2016	2015	2014	2013
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	\$ 134,674	\$ 110,215	\$ 129,925	\$ 200,494	\$ 220,156
Income from equity affiliates and other income	7,048	4,257	8,552	11,476	8,692
Total Revenues and Other Income	141,722	114,472	138,477	211,970	228,848
Total Costs and Other Deductions					
	132,501	116,632	133,635	180,768	192,943
Income Before Income Tax Expense (Benefit)	9,221	(2,160)	4,842	31,202	35,905
Income Tax Expense (Benefit)	(48)	(1,729)	132	11,892	14,308
Net Income	9,269	(431)	4,710	19,310	21,597
Less: Net income attributable to noncontrolling interests	74	66	123	69	174
Net Income (Loss) Attributable to Chevron Corporation	\$ 9,195	\$ (497)	\$ 4,587	\$ 19,241	\$ 21,423
Per Share of Common Stock					
Net Income (Loss) Attributable to Chevron					
– Basic	\$ 4.88	\$ (0.27)	\$ 2.46	\$ 10.21	\$ 11.18
– Diluted	\$ 4.85	\$ (0.27)	\$ 2.45	\$ 10.14	\$ 11.09
Cash Dividends Per Share	\$ 4.32	\$ 4.29	\$ 4.28	\$ 4.21	\$ 3.90
Balance Sheet Data (at December 31)					
Current assets	\$ 28,560	\$ 29,619	\$ 34,430	\$ 41,161	\$ 48,909
Noncurrent assets	225,246	230,459	230,110	223,723	203,884
Total Assets	253,806	260,078	264,540	264,884	252,793
Short-term debt	5,192	10,840	4,927	3,790	374
Other current liabilities	22,545	20,945	20,540	27,322	32,061
Long-term debt and capital lease obligations	33,571	35,286	33,622	23,994	20,027
Other noncurrent liabilities	43,179	46,285	51,565	53,587	49,904
Total Liabilities	104,487	113,356	110,654	108,693	102,366
Total Chevron Corporation Stockholders' Equity	\$ 148,124	\$ 145,556	\$ 152,716	\$ 155,028	\$ 149,113
Noncontrolling interests	1,195	1,166	1,170	1,163	1,314
Total Equity	\$ 149,319	\$ 146,722	\$ 153,886	\$ 156,191	\$ 150,427
* Includes excise, value-added and similar taxes:	\$ 7,189	\$ 6,905	\$ 7,359	\$ 8,186	\$ 8,492

Five-Year Operating Summary

Unaudited

<i>Worldwide – Includes Equity in Affiliates</i>					
<i>Thousands of barrels per day, except natural gas data, which is millions cubic feet per day</i>					
	2017	2016	2015	2014	2013
United States					
Net production of crude oil and natural gas liquids	519	504	501	456	449
Net production of natural gas ¹	970	1,120	1,310	1,250	1,246
Net oil-equivalent production	681	691	720	664	657
Refinery input	901	900	924	871	774
Sales of refined products	1,197	1,213	1,228	1,210	1,182
Sales of natural gas liquids	139	145	153	141	142
Total sales of petroleum products	1,336	1,358	1,381	1,351	1,324
Sales of natural gas	3,331	3,317	3,913	3,995	5,483
International					
Net production of crude oil and natural gas liquids ²	1,204	1,215	1,243	1,253	1,282
Net production of natural gas ¹	5,062	4,132	3,959	3,917	3,946
Net oil-equivalent production	2,047	1,903	1,902	1,907	1,940
Refinery input	760	788	778	819	864
Sales of refined products ³	1,493	1,462	1,507	1,501	1,529
Sales of natural gas liquids	93	85	89	86	88
Total sales of petroleum products	1,586	1,547	1,596	1,587	1,617
Sales of natural gas	5,081	4,491	4,299	4,304	4,251
Total Worldwide					
Net production of crude oil and natural gas liquids	1,723	1,719	1,744	1,709	1,731
Net production of natural gas	6,032	5,252	5,269	5,167	5,192
Net oil-equivalent production	2,728	2,594	2,622	2,571	2,597
Refinery input	1,661	1,688	1,702	1,690	1,638
Sales of refined products	2,690	2,675	2,735	2,711	2,711
Sales of natural gas liquids	232	230	242	227	230
Total sales of petroleum products	2,922	2,905	2,977	2,938	2,941
Sales of natural gas	8,412	7,808	8,212	8,299	9,734
Worldwide – Excludes Equity in Affiliates					
Number of completed wells (net) ⁵					
Oil and gas	766	971	1,848	2,248	1,833
Dry	8	12	18	28	20
Productive oil and gas wells (net) ⁴	49,510	52,559	57,454	56,204	56,635
¹ Includes natural gas consumed in operations:					
United States	37	54	66	71	72
International	528	432	430	452	458
² Includes net production of synthetic oil:					
Canada	51	50	47	43	43
Venezuela affiliate	28	28	29	31	25
³ Includes sales of affiliates (MBPD):					
	366	377	420	475	471
⁴ Net wells include wholly owned and the sum of fractional interests in partially owned wells					

In accordance with FASB and SEC disclosure requirements for oil and gas producing activities, this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and

Table I - Costs Incurred in Exploration, Property Acquisitions and Development¹

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2017									
Exploration									
Wells	\$ 479	\$ 3	\$ 1	\$ 36	\$ —	\$ 15	\$ 534	\$ —	\$ —
Geological and geophysical	93	46	4	3	33	5	184	—	—
Rentals and other	157	32	52	60	46	128	475	—	—
Total exploration	729	81	57	99	79	148	1,193	—	—
Property acquisitions ²									
Proved	64	—	—	93	—	—	157	—	—
Unproved	77	—	40	18	1	—	136	—	—
Total property acquisitions	141	—	40	111	1	—	293	—	—
Development ³	4,346	944	1,136	1,324	2,580	121	10,451	3,596	147
Total Costs Incurred⁴	\$ 5,216	\$ 1,025	\$ 1,233	\$ 1,534	\$ 2,660	\$ 269	\$ 11,937	\$ 3,596	\$ 147
Year Ended December 31, 2016									
Exploration									
Wells	\$ 707	\$ 51	\$ 95	\$ 31	\$ 1	\$ 1	\$ 886	\$ —	\$ —
Geological and geophysical	67	3	22	31	16	4	143	—	—
Rentals and other	139	40	70	57	54	32	392	—	—
Total exploration	913	94	187	119	71	37	1,421	—	—
Property acquisitions ²									
Proved	16	—	—	52	—	—	68	—	—
Unproved	27	—	—	—	—	—	27	—	—
Total property acquisitions	43	—	—	52	—	—	95	—	—
Development ³	3,814	1,631	2,014	1,866	3,733	550	13,608	2,211	262
Total Costs Incurred⁴	\$ 4,770	\$ 1,725	\$ 2,201	\$ 2,037	\$ 3,804	\$ 587	\$ 15,124	\$ 2,211	\$ 262
Year Ended December 31, 2015									
Exploration									
Wells	\$ 857	\$ 66	\$ 172	\$ 218	\$ 81	\$ 14	\$ 1,408	\$ —	\$ —
Geological and geophysical	69	6	77	86	107	26	371	—	—
Rentals and other	218	56	121	109	71	68	643	—	—
Total exploration	1,144	128	370	413	259	108	2,422	—	—
Property acquisitions ²									
Proved	23	21	—	54	—	—	98	—	—
Unproved	554	3	30	—	—	—	587	—	—
Total property acquisitions	577	24	30	54	—	—	685	—	—
Development ³	6,275	2,048	3,701	3,924	6,715	995	23,658	1,641	225
Total Costs Incurred⁴	\$ 7,996	\$ 2,200	\$ 4,101	\$ 4,391	\$ 6,974	\$ 1,103	\$ 26,765	\$ 1,641	\$ 225

¹ Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 26, "Asset Retirement Obligations," on page 71.

² Does not include properties acquired in nonmonetary transactions.

³ Includes \$84, \$481 and \$325 costs incurred on major capital projects prior to assignment of proved reserves for consolidated companies in 2017, 2016, and 2015, respectively.

⁴ Reconciliation of consolidated and affiliated companies total cost incurred to Upstream capital and exploratory (C&E) expenditures - \$ billions:

	2017	2016	2015	
Total cost incurred	\$ 15.7	\$ 17.6	\$ 28.6	
Non-oil and gas activities	1.4	2.5	3.5	(Primarily includes LNG, gas-to-liquids and transportation activities.)
ARO	(0.6)	—	(1.0)	
Upstream C&E	\$ 16.4	\$ 20.1	\$ 31.1	Reference page 23 Upstream total

development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves and changes in estimated discounted future net cash flows. The amounts for consolidated companies are organized by geographic areas including the United States, Other Americas, Africa, Asia, Australia/Oceania and Europe. Amounts for affiliated companies include Chevron's equity interests in Tengizchevroil (TCO) in the Republic of Kazakhstan and in other affiliates, principally in Venezuela and Angola. Refer to Note 16, beginning on page 52, for a discussion of the company's major equity affiliates.

Table II - Capitalized Costs Related to Oil and Gas Producing Activities

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
At December 31, 2017									
Unproved properties	\$ 6,466	\$ 2,314	\$ 240	\$ 1,420	\$ 1,986	\$ 23	\$ 12,449	\$ 108	\$ —
Proved properties and related producing assets	66,390	20,696	43,656	55,616	21,544	10,697	218,599	8,956	4,346
Support equipment	2,248	337	1,104	2,050	15,599	132	21,470	1,731	—
Deferred exploratory wells	969	181	406	562	1,323	261	3,702	—	—
Other uncompleted projects	8,333	3,624	2,528	1,889	3,238	1,966	21,578	8,098	457
Gross Capitalized Costs	84,406	27,152	47,934	61,537	43,690	13,079	277,798	18,893	4,803
Unproved properties valuation	977	855	162	535	107	23	2,659	58	—
Proved producing properties – Depreciation and depletion	43,286	11,795	27,916	40,234	3,193	9,306	135,730	4,690	1,468
Support equipment depreciation	1,359	227	712	1,584	870	123	4,875	846	—
Accumulated provisions	45,622	12,877	28,790	42,353	4,170	9,452	143,264	5,594	1,468
Net Capitalized Costs	\$ 38,784	\$ 14,275	\$ 19,144	\$ 19,184	\$ 39,520	\$ 3,627	\$ 134,534	\$ 13,299	\$ 3,335
At December 31, 2016									
Unproved properties	\$ 9,052	\$ 3,063	\$ 263	\$ 1,273	\$ 1,986	\$ 23	\$ 15,660	\$ 108	\$ —
Proved properties and related producing assets	69,924	18,269	38,903	56,070	11,642	10,738	205,546	8,484	3,898
Support equipment	2,249	357	1,083	2,036	8,598	131	14,454	1,632	—
Deferred exploratory wells	750	190	415	602	1,322	261	3,540	—	—
Other uncompleted projects	7,018	5,900	6,152	2,743	17,559	1,804	41,176	5,075	517
Gross Capitalized Costs	88,993	27,779	46,816	62,724	41,107	12,957	280,376	15,299	4,415
Unproved properties valuation	1,673	903	222	483	107	23	3,411	55	—
Proved producing properties – Depreciation and depletion	45,820	11,635	24,463	38,757	2,300	8,643	131,618	4,148	1,170
Support equipment depreciation	1,165	226	657	1,502	571	118	4,239	750	—
Accumulated provisions	48,658	12,764	25,342	40,742	2,978	8,784	139,268	4,953	1,170
Net Capitalized Costs	\$ 40,335	\$ 15,015	\$ 21,474	\$ 21,982	\$ 38,129	\$ 4,173	\$ 141,108	\$ 10,346	\$ 3,245
At December 31, 2015									
Unproved properties	\$ 9,880	\$ 3,216	\$ 271	\$ 1,487	\$ 1,990	\$ 23	\$ 16,867	\$ 108	\$ —
Proved properties and related producing assets	79,891	16,810	36,563	51,509	3,012	9,664	197,449	7,803	3,857
Support equipment	1,970	363	1,229	1,967	1,195	176	6,900	1,452	—
Deferred exploratory wells	438	237	443	612	1,321	261	3,312	—	—
Other uncompleted projects	7,700	5,566	6,517	5,070	29,843	2,332	57,028	3,732	425
Gross Capitalized Costs	99,879	26,192	45,023	60,645	37,361	12,456	281,556	13,095	4,282
Unproved properties valuation	1,667	873	209	438	107	23	3,317	51	—
Proved producing properties – Depreciation and depletion	53,718	8,950	21,904	35,004	1,950	8,074	129,600	3,714	984
Support equipment depreciation	800	208	740	1,420	480	161	3,809	661	—
Accumulated provisions	56,185	10,031	22,853	36,862	2,537	8,258	136,726	4,426	984
Net Capitalized Costs	\$ 43,694	\$ 16,161	\$ 22,170	\$ 23,783	\$ 34,824	\$ 4,198	\$ 144,830	\$ 8,669	\$ 3,298

Table III - Results of Operations for Oil and Gas Producing Activities¹

The company's results of operations from oil and gas producing activities for the years 2017, 2016 and 2015 are shown in the following table. Net income (loss) from exploration and production activities as reported on page 50 reflects income taxes computed on an effective rate basis.

Income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page 50.

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2017									
Revenues from net production									
Sales	\$ 1,548	\$ 999	\$ 487	\$ 5,381	\$ 2,061	\$ 372	\$ 10,848	\$ 4,509	\$ 1,218
Transfers	7,610	1,371	6,533	2,966	937	1,246	20,663	—	—
Total	9,158	2,370	7,020	8,347	2,998	1,618	31,511	4,509	1,218
Production expenses excluding taxes	(3,160)	(1,021)	(1,521)	(2,670)	(304)	(415)	(9,091)	(425)	(306)
Taxes other than on income	(403)	(85)	(115)	(11)	(183)	(3)	(800)	118	(121)
Proved producing properties:									
Depreciation and depletion	(5,092)	(1,046)	(3,531)	(4,134)	(1,176)	(668)	(15,647)	(638)	(365)
Accretion expense ²	(212)	(23)	(144)	(155)	(40)	(60)	(634)	(3)	(16)
Exploration expenses	(299)	(126)	(65)	(108)	(85)	(149)	(832)	—	—
Unproved properties valuation	(204)	(259)	(3)	(52)	—	—	(518)	—	—
Other income (expense) ³	580	(87)	259	273	170	(170)	1,025	(104)	(14)
Results before income taxes	368	(277)	1,900	1,490	1,380	153	5,014	3,457	396
Income tax (expense) benefit	(88)	(64)	(1,199)	(616)	(413)	(174)	(2,554)	(1,037)	20
Results of Producing Operations	\$ 280	\$ (341)	\$ 701	\$ 874	\$ 967	\$ (21)	\$ 2,460	\$ 2,420	\$ 416
Year Ended December 31, 2016									
Revenues from net production									
Sales	\$ 1,178	\$ 1,038	\$ 238	\$ 5,347	\$ 733	\$ 436	\$ 8,970	\$ 3,416	\$ 695
Transfers	5,895	1,134	4,896	2,839	478	727	15,969	—	—
Total	7,073	2,172	5,134	8,186	1,211	1,163	24,939	3,416	695
Production expenses excluding taxes	(3,634)	(1,120)	(1,806)	(2,942)	(250)	(389)	(10,141)	(451)	(359)
Taxes other than on income	(341)	(90)	(104)	(10)	(154)	(2)	(701)	(494)	(67)
Proved producing properties:									
Depreciation and depletion	(5,913)	(2,729)	(2,612)	(3,848)	(425)	(483)	(16,010)	(524)	(196)
Accretion expense ²	(265)	(26)	(134)	(181)	(30)	(66)	(702)	(3)	(12)
Exploration expenses	(399)	(132)	(255)	(109)	(70)	(38)	(1,003)	—	—
Unproved properties valuation	(342)	(31)	(13)	(44)	—	—	(430)	—	—
Other income (expense) ³	681	(103)	(141)	(39)	4	431	833	(113)	(206)
Results before income taxes	(3,140)	(2,059)	69	1,013	286	616	(3,215)	1,831	(145)
Income tax (expense) benefit	1,080	139	(267)	(386)	(94)	(57)	415	(549)	39
Results of Producing Operations	\$ (2,060)	\$ (1,920)	\$ (198)	\$ 627	\$ 192	\$ 559	\$ (2,800)	\$ 1,282	\$ (106)

¹ The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Represents accretion of ARO liability. Refer to Note 26, "Asset Retirement Obligations," on page 71.

³ Includes foreign currency gains and losses, gains and losses on property dispositions and other miscellaneous income and expenses.

Table III - Results of Operations for Oil and Gas Producing Activities¹, continued

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2015									
Revenues from net production									
Sales	\$ 1,475	\$ 1,155	\$ 279	\$ 6,254	\$ 889	\$ 403	\$ 10,455	\$ 4,097	\$ 729
Transfers	7,195	1,089	6,182	3,779	408	829	19,482	—	—
Total	8,670	2,244	6,461	10,033	1,297	1,232	29,937	4,097	729
Production expenses excluding taxes	(4,293)	(1,162)	(1,758)	(3,601)	(162)	(505)	(11,481)	(510)	(365)
Taxes other than on income	(430)	(123)	(124)	(15)	(172)	(2)	(866)	(279)	(31)
Proved producing properties:									
Depreciation and depletion	(7,640)	(2,519)	(2,506)	(3,887)	(217)	(556)	(17,325)	(501)	(169)
Accretion expense ²	(265)	(23)	(127)	(158)	(37)	(69)	(679)	(3)	(14)
Exploration expenses	(1,614)	(137)	(667)	(492)	(289)	(106)	(3,305)	—	(1)
Unproved properties valuation	(583)	(55)	(24)	(79)	(61)	—	(802)	—	—
Other income (expense) ³	220	(291)	638	21	73	237	898	(25)	373
Results before income taxes	(5,935)	(2,066)	1,893	1,822	432	231	(3,623)	2,779	522
Income tax expense	2,133	550	(986)	(679)	(178)	(62)	778	(835)	(291)
Results of Producing Operations	\$ (3,802)	\$ (1,516)	\$ 907	\$ 1,143	\$ 254	\$ 169	\$ (2,845)	\$ 1,944	\$ 231

¹ The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Represents accretion of ARO liability. Refer to Note 26, "Asset Retirement Obligations," on page 71.

³ Includes foreign currency gains and losses, gains and losses on property dispositions, and other miscellaneous income and expenses.

Table IV - Results of Operations for Oil and Gas Producing Activities - Unit Prices and Costs¹

	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2017									
Average sales prices									
Liquids, per barrel	\$ 44.53	\$ 51.26	\$ 52.12	\$ 48.45	\$ 52.32	\$ 51.15	\$ 48.61	\$ 41.47	\$ 48.68
Natural gas, per thousand cubic feet	2.11	3.15	1.77	4.12	5.75	5.55	4.07	0.88	2.38
Average production costs, per barrel ²	12.83	18.64	10.88	11.30	3.60	11.95	11.41	3.34	8.51
Year Ended December 31, 2016									
Average sales prices									
Liquids, per barrel	\$ 35.00	\$ 43.89	\$ 41.42	\$ 37.55	\$ 45.32	\$ 39.64	\$ 38.30	\$ 31.83	\$ 31.90
Natural gas, per thousand cubic feet	1.58	3.04	1.60	4.19	4.29	4.77	3.45	1.34	2.24
Average production costs, per barrel ²	14.56	18.79	13.80	11.34	5.97	12.84	13.15	3.67	15.01
Year Ended December 31, 2015									
Average sales prices									
Liquids, per barrel	\$ 42.70	\$ 49.66	\$ 49.88	\$ 46.19	\$ 49.96	\$ 48.53	\$ 46.26	\$ 38.71	\$ 34.92
Natural gas, per thousand cubic feet	1.89	3.24	1.84	4.94	6.17	5.28	3.96	1.57	2.51
Average production costs, per barrel ²	16.60	20.45	12.23	13.55	5.03	17.14	14.60	4.32	17.44

¹ The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

Table V Reserve Quantity Information
Summary of Net Oil and Gas Reserves

	2017			2016			2015		
	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas
<i>Liquids in Millions of Barrels</i>									
<i>Natural Gas in Billions of Cubic Feet</i>									
Proved Developed									
Consolidated Companies									
U.S.	1,031	—	2,096	992	—	2,102	933	—	2,683
Other Americas	101	543	398	92	601	533	109	594	597
Africa	664	—	1,276	640	—	1,039	702	—	1,100
Asia	529	—	4,463	621	—	4,962	660	—	4,933
Australia/Oceania	126	—	9,907	124	—	9,176	60	—	4,330
Europe	83	—	215	77	—	213	76	—	166
Total Consolidated	2,534	543	18,355	2,546	601	18,025	2,540	594	13,809
Affiliated Companies									
TCO	787	—	1,300	920	—	1,402	1,020	—	1,504
Other	84	66	270	92	62	319	91	58	288
Total Consolidated and Affiliated Companies	3,405	609	19,925	3,558	663	19,746	3,651	652	15,601
Proved Undeveloped									
Consolidated Companies									
U.S.	885	—	3,084	420	—	1,574	453	—	1,559
Other Americas	196	—	397	131	3	114	127	3	117
Africa	175	—	1,630	236	—	1,788	255	—	1,837
Asia	102	—	310	99	—	571	130	—	1,023
Australia/Oceania	33	—	3,652	34	—	3,339	93	—	7,543
Europe	62	—	86	61	—	21	67	—	58
Total Consolidated	1,453	—	9,159	981	3	7,407	1,125	3	12,137
Affiliated Companies									
TCO	962	—	883	989	—	840	656	—	764
Other	20	93	769	26	108	767	40	135	935
Total Consolidated and Affiliated Companies	2,435	93	10,811	1,996	111	9,014	1,821	138	13,836
Total Proved Reserves	5,840	702	30,736	5,554	774	28,760	5,472	790	29,437

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting – three deemed commercial and three potentially recoverable. Within the commercial classification are proved reserves and two categories of unproved reserves: probable and possible. The potentially recoverable categories are also referred to as contingent resources. For reserves estimates to be classified as proved, they must meet all SEC and company standards.

Proved oil and gas reserves are the estimated quantities that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future from known reservoirs under existing economic conditions, operating methods and government regulations. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

Proved reserves are classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

Due to the inherent uncertainties and the limited nature of reservoir data, estimates of reserves are subject to change as additional information becomes available.

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the Manager of Global Reserves, an organization that is separate from the Upstream operating organization. The Manager of Global Reserves has more than 30 years' experience working in the oil and gas industry and holds both undergraduate and graduate degrees in geoscience. His experience includes various technical and management roles in providing reserve and resource estimates in support of major capital and exploration projects, and more than 10 years of managing oil and gas

reserves processes. He has been named a Distinguished Lecturer by the American Association of Petroleum Geologists and is an active member of the American Association of Petroleum Geologists, the SEPM Society of Sedimentary Geologists and the Society of Petroleum Engineers.

All RAC members are degreed professionals, each with more than 10 years of experience in various aspects of reserves estimation relating to reservoir engineering, petroleum engineering, earth science or finance. The members are knowledgeable in SEC guidelines for proved reserves classification and receive annual training on the preparation of reserves estimates.

The RAC has the following primary responsibilities: establish the policies and processes used within the operating units to estimate reserves; provide independent reviews and oversight of the business units' recommended reserves estimates and changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Global Reserves Manual*, which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

During the year, the RAC is represented in meetings with each of the company's upstream business units to review and discuss reserve changes recommended by the various asset teams. Major changes are also reviewed with the company's Strategy and Planning Committee, whose members include the Chief Executive Officer and the Chief Financial Officer. The company's annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

RAC subteams also conduct in-depth reviews during the year of many of the fields that have large proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their compliance with the *Global Reserves Manual*. In addition, third-party engineering consultants are used to supplement the company's own reserves estimation controls and procedures, including through the use of third-party audits of selected oil and gas assets.

Technologies Used in Establishing Proved Reserves Additions In 2017, additions to Chevron's proved reserves were based on a wide range of geologic and engineering technologies. Information generated from wells, such as well logs, wire line sampling, production and pressure testing, fluid analysis, and core analysis, was integrated with seismic data, regional geologic studies, and information from analogous reservoirs to provide "reasonably certain" proved reserves estimates. Both proprietary and commercially available analytic tools, including reservoir simulation, geologic modeling and seismic processing, have been used in the interpretation of the subsurface data. These technologies have been utilized extensively by the company in the past, and the company believes that they provide a high degree of confidence in establishing reliable and consistent reserves estimates.

Proved Undeveloped Reserves At the end of 2017, proved undeveloped reserves totaled 4.3 billion barrels of oil-equivalent (BOE), an increase of 721 million BOE from year-end 2016. The increase was due to 736 million BOE in extensions and discoveries, 366 million BOE in revisions, 39 million BOE in acquisitions and 5 million BOE in improved recovery, partially offset by the transfer of 419 million BOE to proved developed and 6 million BOE in sales. A major portion of this reserve increase is attributed to the company's activities in the Midland and Delaware basins.

During 2017, investments totaling approximately \$9.1 billion in oil and gas producing activities and about \$0.1 billion in non-oil and gas producing activities were expended to advance the development of proved undeveloped reserves. In Asia, expenditures during the year totaled approximately \$4.0 billion, primarily related to development projects of the TCO affiliate in Kazakhstan. The United States accounted for about \$3.3 billion related primarily to various development activities in the Gulf of Mexico and the Midland and Delaware basins. In Africa, about \$0.7 billion was expended on various offshore development and natural gas projects in Nigeria, Angola and Republic of Congo. Development activities in Canada were primarily responsible for about \$0.8 billion of expenditures in Other Americas.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect optimal project development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructure or plant capacities that dictate project timing, compression projects that are pending reservoir pressure declines, and contractual limitations that dictate production levels.

At year-end 2017, the company held approximately 2.3 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more. The majority of these reserves are in three locations where the company has a proven track record of developing major projects. In Australia, approximately 600 million BOE have remained undeveloped for five years or more related to the Gorgon and Wheatstone projects. The company completed construction of liquefaction and other facilities to develop this natural gas. Further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion. In Africa, approximately 400 million BOE have remained undeveloped for five years or more, primarily due to facility constraints at various fields and infrastructure associated with the Escravos

gas projects in Nigeria. Affiliates account for about 1.4 billion BOE of proved undeveloped reserves with about 1.0 billion BOE that have remained undeveloped for five years or more, with the majority related to the TCO affiliate in Kazakhstan. At TCO, further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion.

Annually, the company assesses whether any changes have occurred in facts or circumstances, such as changes to development plans, regulations or government policies, that would warrant a revision to reserve estimates. In 2017, increases in commodity prices positively impacted the economic limits of oil and gas properties, resulting in proved reserve increases, and negatively impacted proved reserves due to entitlement effects. The year-end reserves volumes have been updated for these circumstances and significant changes have been discussed in the appropriate reserves sections. For 2017, this assessment did not result in any material changes in reserves classified as proved undeveloped. Over the past three years, the ratio of proved undeveloped reserves to total proved reserves has ranged between 32 percent and 38 percent. The consistent completion of major capital projects has kept the ratio in a narrow range over this time period.

Proved Reserve Quantities For the three years ending December 31, 2017, the pattern of net reserve changes shown in the following tables are not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves can be affected by events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, changes in oil and gas prices, OPEC constraints, geopolitical uncertainties, and civil unrest.

At December 31, 2017, proved reserves for the company were 11.7 billion BOE. The company's estimated net proved reserves of liquids including crude oil, condensate, natural gas liquids and synthetic oil for the years 2015, 2016 and 2017 are shown in the table on page 81. The company's estimated net proved reserves of natural gas are shown on page 82.

Noteworthy changes in liquids proved reserves for 2015 through 2017 are discussed below and shown in the table on the following page:

Revisions In 2015, entitlement effects and improved performance were responsible for the 163 million barrel increase in the TCO affiliate in Kazakhstan. In Asia, entitlement effects and drilling performance across numerous assets resulted in the 164 million barrel increase. Improved field performance at various Nigerian fields, including Agbami, was primarily responsible for the 60 million barrel increase in Africa. Synthetic oil reserves in Canada increased by 80 million barrels, primarily due to entitlement effects.

In 2016, entitlement effects were mainly responsible for the 64 million barrel increase in the TCO affiliate in Kazakhstan. Improved field performance at various Gulf of Mexico fields, including Jack/St Malo, and in the San Joaquin Valley were primarily responsible for the 109 million barrel increase in the United States. In Asia, entitlement effects, drilling and improved performance across numerous assets resulted in the 50 million barrel increase.

In 2017, improved field performance at various Gulf of Mexico fields, including Jack/St Malo and Tahiti, and in the Midland and Delaware basins were primarily responsible for the 280 million barrel increase in the United States. Improved field performance at various fields, including Agbami and Sonam in Nigeria, were responsible for the 79 million barrel increase in Africa. Synthetic oil reserves in Canada decreased by 42 million barrels, primarily due to entitlement effects. In the TCO affiliate in Kazakhstan, entitlement effects were mainly responsible for the 53 million barrel decrease.

Improved Recovery In 2016, improved recovery increased reserves by 293 million barrels, primarily due to the Future Growth Project in the TCO affiliate in Kazakhstan.

Extensions and Discoveries In 2015, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 137 million barrel increase in the United States.

In 2016, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 131 million barrel increase in the United States.

In 2017, extensions and discoveries in the Midland and Delaware basins and the Gulf of Mexico were primarily responsible for the 458 million barrel increase in the United States. Extensions and discoveries in the Duvernay Shale in Canada were primarily responsible for the 74 million barrel increase in Other Americas.

Purchases In 2017, purchases of 33 million barrels in Asia were due to contract extension in the Azeri-Chirag-Gunashli fields in Azerbaijan.

Sales In 2016, sales of 34 million barrels in the United States were primarily in the Gulf of Mexico shelf.

In 2017, sales of 57 million barrels in the United States were primarily in the Gulf of Mexico shelf and in the Midland and Delaware basins.

Net Proved Reserves of Crude Oil, Condensate, Natural Gas Liquids and Synthetic Oil

Millions of barrels	Consolidated Companies							Affiliated Companies			Total Consolidated and Affiliated Companies	
	U.S.	Other Americas ¹	Africa	Asia	Australia/Oceania	Europe	Synthetic Oil ²	Total	TCO	Synthetic Oil		Other ³
Reserves at January 1, 2015	1,432	238	1,021	752	142	166	534	4,285	1,615	204	145	6,249
Changes attributable to:												
Revisions	(1)	(9)	60	164	14	(3)	80	305	163	—	(4)	464
Improved recovery	7	—	11	2	—	—	—	20	—	—	—	20
Extensions and discoveries	137	28	4	5	5	—	—	179	—	—	—	179
Purchases	—	—	—	—	—	—	—	—	—	—	—	—
Sales	(6)	—	(7)	—	—	—	—	(13)	—	—	—	(13)
Production	(183)	(21)	(132)	(133)	(8)	(20)	(17)	(514)	(102)	(11)	(10)	(637)
Reserves at December 31, 2015⁴	1,386	236	957	790	153	143	597	4,262	1,676	193	131	6,262
Changes attributable to:												
Revisions	109	(20)	22	50	12	16	26	215	64	(12)	(5)	262
Improved recovery	5	—	11	2	—	—	—	18	273	—	2	293
Extensions and discoveries	131	23	9	1	—	—	—	164	—	—	—	164
Purchases	—	10	—	—	—	—	—	10	—	—	—	10
Sales	(34)	—	—	—	—	—	—	(34)	—	—	—	(34)
Production	(185)	(26)	(123)	(123)	(7)	(21)	(19)	(504)	(104)	(11)	(10)	(629)
Reserves at December 31, 2016⁴	1,412	223	876	720	158	138	604	4,131	1,909	170	118	6,328
Changes attributable to:												
Revisions	280	25	79	(17)	11	30	(42)	366	(53)	—	(5)	308
Improved recovery	9	—	7	1	—	—	—	17	—	—	3	20
Extensions and discoveries	458	74	4	—	—	—	—	536	—	—	—	536
Purchases	4	—	2	33	—	—	—	39	—	—	—	39
Sales	(57)	(1)	—	(2)	—	—	—	(60)	—	—	—	(60)
Production	(190)	(24)	(129)	(104)	(10)	(23)	(19)	(499)	(107)	(11)	(12)	(629)
Reserves at December 31, 2017⁴	1,916	297	839	631	159	145	543	4,530	1,749	159	104	6,542

¹ Ending reserve balances in North America were 234, 169 and 155 and in South America were 63, 54 and 81 in 2017, 2016 and 2015, respectively.

² Reserves associated with Canada.

³ Ending reserve balances in Africa were 26, 31 and 34 and in South America were 78, 87 and 97 in 2017, 2016 and 2015, respectively.

⁴ Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 85 for the definition of a PSC). PSC-related reserve quantities are 15 percent, 19 percent and 20 percent for consolidated companies for 2017, 2016 and 2015, respectively.

Net Proved Reserves of Natural Gas

Billions of cubic feet (BCF)	Consolidated Companies						Affiliated Companies		Total Consolidated and Affiliated Companies	
	U.S.	Other Americas ¹	Africa	Asia	Australia/Oceania	Europe	Total	TCO		Other ²
Reserves at January 1, 2015	4,174	1,123	2,968	6,266	10,941	235	25,707	2,177	1,232	29,116
Changes attributable to:										
Revisions	(66)	(435)	27	480	974	49	1,029	218	2	1,249
Improved recovery	1	—	—	—	—	—	1	—	—	1
Extensions and discoveries	659	147	61	61	118	—	1,046	—	—	1,046
Purchases	—	—	—	—	—	—	—	—	—	—
Sales	(48)	—	(5)	—	—	—	(53)	—	—	(53)
Production ³	(478)	(121)	(114)	(851)	(160)	(60)	(1,784)	(127)	(11)	(1,922)
Reserves at December 31, 2015⁴	4,242	714	2,937	5,956	11,873	224	25,946	2,268	1,223	29,437
Changes attributable to:										
Revisions	(6)	(24)	(29)	443	853	72	1,309	111	(107)	1,313
Improved recovery	2	—	—	—	—	—	2	—	—	2
Extensions and discoveries	388	73	—	4	14	—	479	—	—	479
Purchases	4	3	—	—	—	—	7	—	—	7
Sales	(544)	(10)	—	—	—	—	(554)	—	—	(554)
Production ³	(410)	(109)	(81)	(870)	(225)	(62)	(1,757)	(137)	(30)	(1,924)
Reserves at December 31, 2016⁴	3,676	647	2,827	5,533	12,515	234	25,432	2,242	1,086	28,760
Changes attributable to:										
Revisions	670	39	184	65	1,545	143	2,646	87	48	2,781
Improved recovery	3	—	—	—	—	—	3	—	—	3
Extensions and discoveries	1,361	319	—	2	—	—	1,682	—	—	1,682
Purchases	1	—	2	46	—	—	49	—	—	49
Sales	(177)	(129)	—	(31)	—	—	(337)	—	—	(337)
Production ³	(354)	(81)	(107)	(842)	(501)	(76)	(1,961)	(146)	(95)	(2,202)
Reserves at December 31, 2017⁴	5,180	795	2,906	4,773	13,559	301	27,514	2,183	1,039	30,736

¹ Ending reserve balances in North America and South America were 478, 172, 174 and 317, 475, 540 in 2017, 2016 and 2015, respectively.

² Ending reserve balances in Africa and South America were 899, 939, 1,044 and 140, 147, 179 in 2017, 2016 and 2015, respectively.

³ Total "as sold" volumes are 1,995, 1,744 and 1,742 for 2017, 2016 and 2015, respectively.

⁴ Includes reserve quantities related to production-sharing contracts (PSC) (refer to page 85 for the definition of a PSC). PSC-related reserve quantities are 12 percent, 15 percent and 16 percent for consolidated companies for 2017, 2016 and 2015, respectively.

Noteworthy changes in natural gas proved reserves for 2015 through 2017 are discussed below and shown in the table above:

Revisions In 2015, positive drilling performance at Wheatstone and Gorgon was responsible for the 974 BCF increase in Australia. Net revisions of 480 BCF in Asia were primarily due to improved field performance in Thailand and to entitlement effects and improved performance in Kazakhstan. The majority of the net decrease of 435 BCF in Other Americas was due to the deferral of the infill drilling and compression projects as well as drilling results in Trinidad and Tobago. The 218 BCF increase for the TCO affiliate was due to entitlement effects and improved performance.

In 2016, development activities primarily at Wheatstone were responsible for the 853 BCF increase in Australia. Net revisions of 443 BCF in Asia were primarily due to improved field performance in China and Thailand.

In 2017, reservoir performance and new seismic data in the greater Gorgon area were primarily responsible for the 1.5 TCF increase in Australia. Improved performance in the Midland and Delaware basins were primarily responsible for the 670 BCF increase in the United States. The Sonam Field in Nigeria was primarily responsible for the 184 BCF increase in Africa.

Extensions and Discoveries In 2015, extensions and discoveries of 659 BCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins.

In 2016, extensions and discoveries of 388 BCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins.

In 2017, extensions and discoveries of 1.4 TCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins. Extensions and discoveries in the Duvernay Shale in Canada were primarily responsible for the 319 BCF increase in Other Americas.

Sales In 2016, sales of 544 BCF in the United States were primarily in the Gulf of Mexico shelf, Michigan and the midcontinent region.

In 2017, sales of 177 BCF in the United States were primarily from the Midland and Delaware basins. Sale of the company's interests in Trinidad and Tobago was primarily responsible for the 129 BCF decrease in Other Americas.

Table VI - Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows is calculated in accordance with SEC and FASB requirements. This includes using the average of first-day-of-the-month oil and gas prices for the 12-month period prior to the end of the reporting period, estimated future development and production costs assuming the continuation of existing economic conditions, estimated costs for asset retirement obligations (includes costs to retire existing wells and facilities in addition to those future wells and facilities necessary to produce proved undeveloped reserves), and estimated future income taxes based on appropriate statutory tax rates. Discounted future net cash flows are calculated using 10 percent mid-period discount factors. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. The valuation requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and do not represent management's estimate of the company's future cash flows or value of its oil and gas reserves. In the following table, the caption "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

Millions of dollars	Consolidated Companies						Affiliated Companies		Total Consolidated and Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO		Other
At December 31, 2017										
Future cash inflows from production	\$ 94,086	\$ 43,175	\$ 47,828	\$ 47,809	\$ 77,557	\$ 8,800	\$ 319,255	\$ 80,090	\$ 13,632	\$ 412,977
Future production costs	(29,049)	(20,044)	(18,124)	(18,640)	(12,315)	(6,345)	(104,517)	(22,050)	(4,635)	(131,202)
Future development costs	(10,849)	(5,102)	(3,808)	(4,755)	(6,682)	(1,114)	(32,310)	(17,564)	(1,760)	(51,634)
Future income taxes	(10,803)	(5,158)	(17,845)	(10,901)	(17,568)	(615)	(62,890)	(12,143)	(3,250)	(78,283)
Undiscounted future net cash flows	43,385	12,871	8,051	13,513	40,992	726	119,538	28,333	3,987	151,858
10 percent midyear annual discount for timing of estimated cash flows	(19,781)	(8,483)	(2,058)	(3,846)	(19,730)	207	(53,691)	(16,310)	(1,844)	(71,845)
Standardized Measure Net Cash Flows	\$ 23,604	\$ 4,388	\$ 5,993	\$ 9,667	\$ 21,262	\$ 933	\$ 65,847	\$ 12,023	\$ 2,143	\$ 80,013
At December 31, 2016										
Future cash inflows from production	\$ 53,777	\$ 33,520	\$ 39,072	\$ 44,526	\$ 63,781	\$ 6,338	\$ 241,014	\$ 66,506	\$ 11,244	\$ 318,764
Future production costs	(26,530)	(20,413)	(19,749)	(19,815)	(11,058)	(5,500)	(103,065)	(13,610)	(5,254)	(121,929)
Future development costs	(7,830)	(4,277)	(4,186)	(4,603)	(7,804)	(977)	(29,677)	(20,855)	(2,192)	(52,724)
Future income taxes	(3,454)	(2,664)	(9,684)	(8,503)	(13,476)	69	(37,712)	(9,613)	(1,639)	(48,964)
Undiscounted future net cash flows	15,963	6,166	5,453	11,605	31,443	(70)	70,560	22,428	2,159	95,147
10 percent midyear annual discount for timing of estimated cash flows *	(5,123)	(3,646)	(1,336)	(3,137)	(15,284)	322	(28,204)	(13,902)	(972)	(43,078)
Standardized Measure Net Cash Flows	\$ 10,840	\$ 2,520	\$ 4,117	\$ 8,468	\$ 16,159	\$ 252	\$ 42,356	\$ 8,526	\$ 1,187	\$ 52,069
At December 31, 2015										
Future cash inflows from production	\$ 67,536	\$ 39,363	\$ 52,128	\$ 58,645	\$ 93,550	\$ 8,561	\$ 319,783	\$ 75,378	\$ 17,519	\$ 412,680
Future production costs	(33,895)	(26,477)	(22,963)	(27,499)	(10,814)	(6,994)	(128,642)	(17,959)	(6,546)	(153,147)
Future development costs	(12,625)	(5,485)	(6,562)	(8,924)	(11,612)	(1,751)	(46,959)	(17,232)	(3,226)	(67,417)
Future income taxes	(4,161)	(2,316)	(14,681)	(9,229)	(21,337)	70	(51,654)	(12,056)	(3,460)	(67,170)
Undiscounted future net cash flows	16,855	5,085	7,922	12,993	49,787	(114)	92,528	28,131	4,287	124,946
10 percent midyear annual discount for timing of estimated cash flows *	(5,921)	(2,833)	(2,207)	(3,673)	(26,121)	282	(40,473)	(15,249)	(2,242)	(57,964)
Standardized Measure Net Cash Flows	\$ 10,934	\$ 2,252	\$ 5,715	\$ 9,320	\$ 23,666	\$ 168	\$ 52,055	\$ 12,882	\$ 2,045	\$ 66,982

* Conforms to 2017 presentation.

Table VII - Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves

The changes in present values between years, which can be significant, reflect changes in estimated proved-reserve quantities and prices and assumptions used in forecasting production volumes and costs. Changes in the timing of production are included with “Revisions of previous quantity estimates.”

<i>Millions of dollars</i>	Consolidated Companies	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2015	\$ 109,521	\$ 35,831	\$ 145,352
Sales and transfers of oil and gas produced net of production costs	(17,145)	(3,637)	(20,782)
Development costs incurred	21,703	1,863	23,566
Purchases of reserves	2	—	2
Sales of reserves	(109)	—	(109)
Extensions, discoveries and improved recovery less related costs	1,415	—	1,415
Revisions of previous quantity estimates	9,171	3,607	12,778
Net changes in prices, development and production costs	(143,055)	(37,056)	(180,111)
Accretion of discount	18,179	4,965	23,144
Net change in income tax *	52,373	9,354	61,727
Net change for 2015	(57,466)	(20,904)	(78,370)
Present Value at December 31, 2015	\$ 52,055	\$ 14,927	\$ 66,982
Sales and transfers of oil and gas produced net of production costs	(14,415)	(2,788)	(17,203)
Development costs incurred	12,732	2,473	15,205
Purchases of reserves	(41)	—	(41)
Sales of reserves	528	—	528
Extensions, discoveries and improved recovery less related costs	1,231	(917)	314
Revisions of previous quantity estimates	12,851	946	13,797
Net changes in prices, development and production costs	(37,198)	(9,798)	(46,996)
Accretion of discount	7,888	2,113	10,001
Net change in income tax *	6,724	2,758	9,482
Net change for 2016	(9,700)	(5,213)	(14,913)
Present Value at December 31, 2016	\$ 42,355	\$ 9,714	\$ 52,069
Sales and transfers of oil and gas produced net of production costs	(21,505)	(5,234)	(26,739)
Development costs incurred	9,417	3,721	13,138
Purchases of reserves	105	—	105
Sales of reserves	(1,148)	—	(1,148)
Extensions, discoveries and improved recovery less related costs	3,716	—	3,716
Revisions of previous quantity estimates	11,132	(1,085)	10,047
Net changes in prices, development and production costs	28,754	8,013	36,767
Accretion of discount	6,116	1,398	7,514
Net change in income tax	(13,095)	(2,361)	(15,456)
Net change for 2017	23,492	4,452	27,944
Present Value at December 31, 2017	\$ 65,847	\$ 14,166	\$ 80,013

* Conforms to 2017 presentation.

glossary of energy and financial terms

energy terms

Additives Specialty chemicals incorporated into fuels and lubricants that enhance the performance of the finished products.

Barrels of oil-equivalent (BOE) A unit of measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content. See *oil-equivalent gas* and *production*.

Condensate Hydrocarbons that are in a gaseous state at reservoir conditions but condense into liquid as they travel up the wellbore and reach surface conditions.

Development Drilling, construction and related activities following discovery that are necessary to begin production and transportation of crude oil and natural gas.

Enhanced recovery Techniques used to increase or prolong production from crude oil and natural gas reservoirs.

Entitlement effects The impact on Chevron's share of net production and net proved reserves due to changes in crude oil and natural gas prices and spending levels between periods. Under production-sharing contracts (PSCs) and variable-royalty provisions of certain agreements, price and spending variability can increase or decrease royalty burdens and/or volumes attributable to the company. For example, at higher prices, fewer volumes are required for Chevron to recover its costs under certain PSCs. Also under certain PSCs, Chevron's share of future profit oil and/or gas is reduced once specified contractual thresholds are met, such as a cumulative return on investment.

Exploration Searching for crude oil and/or natural gas by utilizing geologic and topographical studies, geophysical and seismic surveys, and drilling of wells.

Gas-to-liquids (GTL) A process that converts natural gas into high-quality liquid transportation fuels and other products.

Greenhouse gases Gases that trap heat in Earth's atmosphere (e.g., water vapor, ozone, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride).

Integrated energy company A company engaged in all aspects of the energy industry, including exploring for and producing crude oil and natural gas; refining, marketing and transporting crude oil, natural gas and refined products; manufacturing and distributing petrochemicals; and generating power.

Liquefied natural gas (LNG) Natural gas that is liquefied under extremely cold temperatures to facilitate storage or transportation in specially designed vessels.

Natural gas liquids (NGLs) Separated from natural gas, these include ethane, propane, butane and natural gasoline.

Oil-equivalent gas (OEG) The volume of natural gas needed to generate the equivalent amount of heat as a barrel of crude oil. Approximately 6,000 cubic feet of natural gas is equivalent to one barrel of crude oil.

Oil sands Naturally occurring mixture of *bitumen* (a heavy, viscous form of crude oil), water, sand and clay. Using hydroprocessing technology, bitumen can be refined to yield synthetic oil.

Petrochemicals Compounds derived from petroleum. These include aromatics, which are used to make plastics, adhesives, synthetic fibers and household detergents; and olefins, which are used to make packaging, plastic pipes, tires, batteries, household detergents and synthetic motor oils.

Production *Total production* refers to all the crude oil (including synthetic oil), NGLs and natural gas produced from a property. *Net production* is the company's share of total production after deducting both royalties paid to landowners and a government's agreed-upon share of production under a PSC. *Liquids production* refers to crude oil, condensate, NGLs and synthetic oil volumes. *Oil-equivalent production* is the sum of the barrels of *liquids* and the oil-equivalent barrels of natural gas produced. See *barrels of oil-equivalent* and *oil-equivalent gas*.

Production-sharing contract (PSC) An agreement between a government and a contractor (generally an oil and gas company) whereby production is shared between the parties in a prearranged manner. The contractor typically incurs all exploration, development and production costs, which are subsequently recoverable out of an agreed-upon share of any future PSC production, referred to as cost recovery oil and/or gas. Any remaining production, referred to as profit oil and/or gas, is shared between the parties on an agreed-upon basis as stipulated in the PSC. The government may also retain a share of PSC production as a royalty payment, and the contractor typically owes income tax on its portion of the profit oil and/or gas. The contractor's share of PSC oil and/or gas production and reserves varies over time as it is dependent on prices, costs and specific PSC terms.

Reserves Crude oil and natural gas contained in underground rock formations called reservoirs and saleable hydrocarbons extracted from oil sands, shale, coalbeds and other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas. *Net proved reserves* are the estimated quantities that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future from known reservoirs under existing economic conditions, operating methods and government regulations and exclude royalties and interests owned by others. Estimates change as additional information becomes available. *Oil-equivalent reserves* are the sum of the liquids reserves and the oil-equivalent gas reserves. See *barrels of oil-equivalent* and *oil-equivalent gas*. The company discloses only net proved reserves in its filings with the U.S. Securities and Exchange Commission. Investors should refer to proved reserves disclosures in Chevron's *Annual Report on Form 10-K* for the year ended December 31, 2017.

Resources Estimated quantities of oil and gas resources are recorded under Chevron's 6P system, which is modeled after the Society of Petroleum Engineers' Petroleum Resource Management System, and include quantities classified as proved, probable and possible reserves, plus those that remain contingent on commerciality. *Unrisked resources*, *unrisked resource base* and similar terms represent the arithmetic sum of the amounts recorded under each of these classifications. *Recoverable resources*, *potentially recoverable volumes* and similar terms represent estimated remaining quantities that are expected to be ultimately

recoverable and produced in the future, adjusted to reflect the relative uncertainty represented by the various classifications. These estimates may change significantly as development work provides additional information. At times, *original oil in place* and similar terms are used to describe total hydrocarbons contained in a reservoir without regard to the likelihood of their being produced. All of these measures are considered by management in making capital investment and operating decisions and may provide some indication to stockholders of the resource potential of oil and gas properties in which the company has an interest.

Shale gas Natural gas produced from shale rock formations where the gas was sourced from within the shale itself. Shale is very fine-grained rock, characterized by low porosity and extremely low permeability. Production of shale gas normally requires formation stimulation such as the use of hydraulic fracturing (pumping a fluid-sand mixture into the formation under high pressure) to help produce the gas.

Synthetic oil A marketable and transportable hydrocarbon liquid, resembling crude oil, that is produced by upgrading highly viscous or solid hydrocarbons, such as extra-heavy crude oil and oil sands.

Tight oil Liquid hydrocarbons produced from shale (also referred to as shale oil) and other rock formations with extremely low permeability. As with shale gas, production from tight oil reservoirs normally requires formation stimulation such as hydraulic fracturing.

financial terms

Cash flow from operating activities Cash generated from the company's businesses; an indicator of a company's ability to fund capital programs and stockholder distributions. Excludes cash flows related to the company's financing and investing activities.

Debt ratio Total debt, including capital lease obligations, divided by total debt plus Chevron Corporation stockholders' equity.

Earnings Net income attributable to Chevron Corporation as presented on the Consolidated Statement of Income.

Margin The difference between the cost of purchasing, producing and/or marketing a product and its sales price.

Return on capital employed (ROCE) Ratio calculated by dividing earnings (adjusted for after-tax interest expense and noncontrolling interests) by the average of total debt, noncontrolling interests and Chevron Corporation stockholders' equity for the year.

Return on stockholders' equity Ratio calculated by dividing earnings by average Chevron Corporation stockholders' equity. Average Chevron Corporation stockholders' equity is computed by averaging the sum of the beginning-of-year and end-of-year balances.

Total stockholder return (TSR) The return to stockholders as measured by stock price appreciation and reinvested dividends for a period of time.

the chevron way

getting results the right way

The Chevron Way explains who we are, what we believe, how we achieve and where we aspire to go. It establishes a common understanding not only for us, but also for all who interact with us.

vision

At the heart of The Chevron Way is our vision ... to be *the* global energy company most admired for its people, partnership and performance.

enabling human progress

We develop the energy that improves lives and powers the world forward.

values

Our company's foundation is built on our values, which distinguish us and guide our actions to deliver results. We conduct our business in a socially and environmentally responsible manner, respecting the law and universal human rights to benefit the communities where we work.



diversity and inclusion

We learn from and respect the cultures in which we operate. We have an inclusive work environment that values the uniqueness and diversity of individual talents, experiences and ideas.



high performance

We are passionate about delivering results, and strive to continually improve. We hold ourselves accountable for our actions and outcomes. We apply proven processes in a fit-for-purpose manner and always look for innovative and agile solutions.



integrity and trust

We are honest with ourselves and others, and honor our commitments. We trust, respect and support each other. We earn the trust of our colleagues and partners by operating with the highest ethical standards in all we do.



partnership

We build trusting and mutually beneficial relationships by collaborating with our communities, governments, customers, suppliers and other business partners. We are most successful when our partners succeed with us.



protect people and the environment

We place the highest priority on the health and safety of our workforce and protection of our assets, communities and the environment. We deliver world-class performance with a focus on preventing high-consequence incidents.



strategies

Our strategies guide our actions to deliver industry-leading results and superior shareholder value in any business environment.

major business strategies



Upstream

Deliver industry-leading returns while developing high-value resource opportunities



Downstream & Chemicals

Grow earnings across the value chain and make targeted investments to lead the industry in returns



Midstream

Deliver operational, commercial and technical expertise to enhance results in Upstream and Downstream & Chemicals

enterprise strategies



People

Invest in people to develop and empower a highly competent workforce that delivers results the right way



Execution

Deliver results through disciplined operational excellence, capital stewardship and cost efficiency



Growth

Grow profits and returns by using our competitive advantages



Technology and functional excellence

Differentiate performance through technology and functional expertise

Photo: A lab technician at the Pascagoula Refinery, in Mississippi, examines a crucible before placing it in an evaporation analyzer under a fume hood. The technician is testing to determine evaporation loss of lubricating oils. At the laboratory, chemists and technicians conduct quality assurance tests on all finished products, including checking gasoline for proper octane rating.

board of directors



Michael K. Wirth, 57

Chairman of the Board and Chief Executive Officer since February 2018. Previously, he was Vice Chairman in 2017; Executive Vice President, Midstream & Development; Executive Vice President, Downstream & Chemicals; President, Global Supply and Trading; and President, Marketing, Asia/Middle East/Africa. He serves on the Board of Directors and the Executive Committee of the American Petroleum Institute. Joined Chevron in 1982.

Wanda M. Austin, 63

Director since 2016. She holds an adjunct Research Professor appointment at the University of Southern California's Viterbi School's Department of Industrial and Systems Engineering. Previously, she served as President and Chief Executive Officer of the Aerospace Corporation, a leading architect for the United States' national security space programs. She is a Director of Amgen Inc. (2, 4)

John B. Frank, 61

Director since 2017. He is Vice Chairman of Oaktree Capital Group, LLC, a leader among global investment managers specializing in alternative investments. Previously, he was Managing Principal, having joined Oaktree in 2001 as General Counsel. He is a Director of Oaktree Capital Group, LLC, Oaktree Specialty Lending Corporation; and Oaktree Strategic Income Corporation. (1)

Alice P. Gast, 59

Director since 2012. She is President of Imperial College London, a public research university specializing in science, engineering, medicine and business. Previously, she was President of Lehigh University in Pennsylvania. Prior to that, she was Vice President for Research, Associate Provost and Robert T. Haslam Chair in Chemical Engineering at the Massachusetts Institute of Technology. (2, 4)

Enrique Hernandez, Jr., 62

Director since 2008. He is Chairman, Chief Executive Officer and President of Inter-Con Security Systems, Inc., a global provider of security and facility support services to governments, utilities and industrial customers. He is Chairman of the Board of McDonald's Corporation and a Director of Wells Fargo & Company (retiring April 24, 2018). (3, 4)



Charles W. Moorman IV, 66

Director since 2012. He is retired Chairman of the Board and Chief Executive Officer of Norfolk Southern Corporation, a freight and transportation company. He also served as President at Norfolk Southern from 2004 to 2013. He is Senior Advisor and retired President and Chief Executive Officer of Amtrak, a passenger rail service provider. He is a Director of Duke Energy Corporation. (1)

Dambisa F. Moyo, 49

Director since 2016. She is Chief Executive Officer of Mildstorm LLC, focusing on the global economy and international affairs. Previously, she worked at Goldman Sachs in various roles and at the World Bank in Washington, D.C. She is the author of three *New York Times* bestsellers and is a Director of Barclays plc and Barrick Gold Corporation. (1)

Ronald D. Sugar, 69

Lead Director since 2015 and a Director since 2005. He is a retired Chairman of the Board and Chief Executive Officer of Northrop Grumman Corporation. He is a Senior Advisor to various businesses and organizations, including Ares Management LLC, a leading private investment firm; Bain & Company, a global consulting firm; Temasek Americas Advisory Panel, a private investment company based in Singapore; and the G100 Network and the World 50, peer-to-peer exchanges for current and former senior executives from some of the world's largest companies. He is a Director of Air Lease Corporation, Amgen Inc. and Apple Inc. (2, 3)

Inge G. Thulin, 64

Director since 2015. He is Chairman of the Board, President and Chief Executive Office of 3M Company, a diversified technology company. Previously, he was Executive Vice President and Chief Operating Officer of 3M. Prior to that, he was the company's Executive Vice President of International Operations. He is a Director of Merck & Co. (2, 3)

D. James Umpleby III, 60

Director since 2018. He is Chief Executive Officer of Caterpillar Inc., a leading manufacturer of construction and mining equipment, diesel and natural gas engines, industrial gas turbines, and diesel-electric locomotives. Previously, he was Group President of Caterpillar's Energy and Transportation business segment. He is a Director of Caterpillar Inc. (2, 3)

Committees of the Board

- 1) Audit: Charles W. Moorman IV, Chair
- 2) Board Nominating and Governance: Ronald D. Sugar, Chair
- 3) Management Compensation: Enrique Hernandez, Jr., Chair
- 4) Public Policy: Linnet F. Deily, Chair

Retiring Directors

(left to right) **John S. Watson** retired effective February 1, 2018, after a 37-year career with Chevron. He had been Chairman of the Board and Chief Executive Officer since 2010. Previously, he was elected Vice Chairman in 2009. Watson graduated from the University of California at Davis with a bachelor's degree in agricultural economics and from the University of Chicago with a master's degree in business administration. He joined the corporation in 1980 and was elected a vice president in 1998. Two Directors have reached the Board's mandatory retirement age and will not stand for reelection at the Annual Meeting in May: **Linnet F. Deily**, a Director since 2006, served as Deputy U.S. Trade Representative and U.S. Ambassador to the World Trade Organization (2, 4); and **Robert E. Denham**, a Director since 2004, is a Partner in the law firm of Munger, Tolles & Olson LLP (1, 3).



corporate officers



Pierre R. Breber, 53

Executive Vice President, Downstream & Chemicals, since 2016. Responsible for directing the company's worldwide manufacturing, marketing, lubricants, chemicals and Oronite additives businesses and Chevron's joint-venture Chevron Phillips Chemical Company. Previously, Executive Vice President, Gas & Midstream, and Managing Director, Asia South Business Unit. Joined the company in 1989.

Mary A. Francis, 53

Corporate Secretary and Chief Governance Officer since 2015. Responsible for providing advice and counsel to the Board of Directors and senior management on corporate governance matters, managing the company's corporate governance function, and serving on the Law Function Executive Committee. Previously, Chief Corporate Counsel, Corporation Law Department, and Counsel, Chevron Asia Pacific Exploration and Production Company. Joined the company in 2002.

Joseph C. Geagea, 58

Executive Vice President, Technology, Projects and Services, since 2015. Responsible for energy technology; delivery of major capital projects; procurement; information technology; health, environment and safety; Upstream production services; and talent selection and development in support of Chevron's Upstream, Downstream and Midstream businesses. Previously, Senior Vice President, Technology, Projects and Services, and Corporate Vice President and President, Chevron Gas & Midstream. Joined the company in 1982.

James W. Johnson, 59

Executive Vice President, Upstream, since 2015. Responsible for Chevron's global exploration and production activities for crude oil and natural gas. Previously, Senior Vice President, Upstream; President, Chevron Europe, Eurasia and Middle East Exploration and Production Company; Managing Director, Eurasia Business Unit; and Managing Director, Australasia Business Unit. Joined the company in 1981.

Wesley E. Lohec, 58

Vice President, Health, Environment and Safety (HES), since 2011. Responsible for HES strategic planning and issues management, compliance assurance, emergency response, Chevron's Environmental Management Company, and Corporate Aviation. Previously, Managing Director, Latin America, Chevron Africa, and Latin America Exploration and Production Company. Joined the company in 1981.

Charles N. Macfarlane, 63

Vice President since 2013 and **General Tax Counsel** since 2010. Responsible for directing Chevron's worldwide tax activities. Previously, the company's Assistant General Tax Counsel. Joined the company in 1986.

Rhonda J. Morris, 52

Vice President, Human Resources, since 2016. Responsible for human resources, diversity, ombuds, and global health and medical groups. Previously, Vice President, Human Resources, Downstream & Chemicals. Joined the company in 1991.



Joseph M. Naylor, 57

Vice President, Policy, Government and Public Affairs, since 2016. Responsible for U.S. and international government relations, all aspects of communications, and the company's worldwide efforts to protect and enhance its reputation. Previously, Vice President, Strategic Planning. Joined the company in 1982.

Mark A. Nelson, 54

Vice President, Midstream, Strategy & Policy, since February 2018. Oversees Chevron's Midstream business with responsibility for the company's supply and trading, shipping, pipeline, and power operating units; oversees Corporate Strategic Planning and Policy, Government and Public Affairs. Previously, Vice President, Strategic Planning, and President, International Products. Joined the company in 1985.

Bruce Niemeyer, 56

Vice President, Strategic Planning, since February 2018. Responsible for setting the strategic direction for the company, allocating capital and other resources, and determining operating unit performance measures and targets. Previously, Vice President of Chevron's Mid-Continent Business Unit; Vice President of the Appalachian/Michigan Strategic Business Unit; and General Manager of Strategy and Planning for Chevron North America Exploration and Production Co. Joined the company in 2001 upon the merger with Texaco Inc.

Jeanette L. Ourada, 52

Vice President and Comptroller since 2015. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, and Finance Shared Services. Previously, General Manager, Finance Shared Services. Joined the company in 2005 upon the merger with Unocal Corporation.

R. Hewitt Pate, 55

Vice President and General Counsel since 2009. Responsible for directing the company's worldwide legal affairs. Previously, Chair, Competition Practice, Hunton & Williams LLP, Washington, D.C., and Assistant Attorney General, Antitrust Division, U.S. Department of Justice. Joined the company in 2009.

Jay R. Pryor, 60

Vice President, Business Development, since 2006. Responsible for identifying and developing new, large-scale Upstream and Downstream business opportunities, including mergers and acquisitions. Previously, Managing Director, Chevron Nigeria Ltd., and Managing Director, Asia South Business Unit and Chevron Offshore (Thailand) Ltd. Joined the company in 1979.

Randolph S. (Randy) Richards, 63

Vice President and Treasurer since 2016. Responsible for banking, financing, cash management, insurance, pension investments, and credit and receivables activities across the corporation. Previously, Vice President, Finance, Upstream. Joined the company in 1979.

Patricia E. Yarrington, 62

Vice President and Chief Financial Officer since 2009. Responsible for comptroller, tax, treasury, audit and investor relations activities. Served as Chairman of the San Francisco Federal Reserve's Board of Directors in 2013 and 2014. Previously, Corporate Vice President and Treasurer; Corporate Vice President, Policy, Government and Public Affairs; Corporate Vice President, Strategic Planning; and President, Chevron Canada Limited. Joined the company in 1980.

Executive Committee

Michael K. Wirth, Pierre R. Breber, Joseph C. Geagea, James W. Johnson, Mark A. Nelson, R. Hewitt Pate and Patricia E. Yarrington.

stockholder and investor information

Stock exchange listing

Chevron common stock is listed on the New York Stock Exchange. The symbol is “CVX.”

Stockholder information

Questions about stock ownership, changes of address, dividend payments and direct deposit of dividends should be directed to Chevron’s transfer agent and registrar:

Computershare
P.O. Box 505000
Louisville, KY 40233-5000
800 368 8357
www.computershare.com/investor

Overnight correspondence should be sent to:

Computershare
462 South 4th Street
Suite 1600
Louisville, KY 40202

The Computershare Investment Plan is a direct stock purchase and dividend reinvestment plan.

Dividend payment dates

Quarterly dividends on common stock are paid, generally, following declaration by the Board of Directors, on or about the 10th day of March, June, September and December. Direct deposit of dividends is available to stockholders. For information, contact Computershare.

(See *Stockholder Information*.)

Annual meeting

The Annual Meeting of stockholders will be held at 8:00 a.m. PDT, Wednesday, May 30, 2018, at:
Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583

Electronic access

In an effort to conserve natural resources and reduce the cost of printing and mailing proxy materials, we encourage stockholders to register to receive these documents via email and vote their shares on the Internet. Stockholders of record may sign up on our website, www.icsdelivery.com/cvx/, for electronic access. Enrollment is revocable until each year’s Annual Meeting record date. Beneficial stockholders may be able to request electronic access by contacting their broker or bank, or Broadridge Financial Solutions at: www.icsdelivery.com/cvx/.

Investor information

Securities analysts, portfolio managers and representatives of financial institutions may contact:

Investor Relations
Chevron Corporation
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Notice

As used in this report, the term “Chevron” and such terms as “the company,” “the corporation,” “our,” “we” and “us” may refer to one or more of Chevron’s consolidated subsidiaries or to all of them taken as a whole. 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.

Corporate headquarters

6001 Bollinger Canyon Road
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Chevron Supply and Trading provides a critical link between the market and Chevron’s Upstream and Downstream & Chemicals companies. We provide commercial support to our crude oil and natural gas production operations and to our refining and marketing network.

Find out more by visiting:

www.chevron.com/operations/supply-trading



Chevron has a 100-year history and long-term investments in Nigeria. In the country's Niger Delta region, we pioneered the Global Memorandum of Understanding (GMOU), a public-private partnership community empowerment program that involves participatory development processes to help resolve conflict and address the needs of communities near our operations.

Shown: Students in front of a renovated classroom built by the Idama Regional Development Committee, whose projects are funded by a Chevron-Nigerian National Petroleum Corporation joint venture.

Publications and other news sources

The *Annual Report*, distributed in April, summarizes the company's financial performance in the preceding year and provides an overview of the company's major activities.

Chevron's *Annual Report on Form 10-K* filed with the U.S. Securities and Exchange Commission and the *Supplement to the Annual Report*, containing additional financial and operating data, are available on the company's website, Chevron.com, or copies may be requested by contacting:

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The *2017 Corporate Responsibility Report* is available in May on the company's website, www.chevron.com/cr, where other Corporate Responsibility information can be found. A printed copy may be requested by writing to: Policy, Government and Public Affairs Corporate Responsibility Communications Chevron Corporation 6001 Bollinger Canyon Road Building G San Ramon, CA 94583-2324

An in-depth report that addresses Chevron's framework for incorporating climate change into our governance, risk management, strategy, and actions and investments is available at www.chevron.com/climate-change-resilience

Details of the company's political contributions for 2017 are available on the company's website, www.chevron.com, or by writing to: Policy, Government and Public Affairs Chevron Corporation 6001 Bollinger Canyon Road Building G San Ramon, CA 94583-2324

For additional information about the company and the energy industry, visit Chevron's website, www.chevron.com. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

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This *Annual Report* contains forward-looking statements – identified by words such as “expect,” “commit,” “position,” “focus,” “goal,” “target,” “schedule,” “plan,” “strategy,” “project,” “forecast,” “on track” and similar phrases – that reflect management's current estimates and beliefs, but are not guarantees of future results. Please see “Cautionary Statement Relevant to Forward-Looking Information for the Purpose of ‘Safe Harbor’ Provisions of the Private Securities Litigation Reform Act of 1995” on Page 11 for a discussion of some of the factors that could cause actual results to differ materially.

PRODUCED BY Policy, Government and Public Affairs and Comptroller's Departments, Chevron Corporation
DESIGN Information Design & Communications, Chevron Corporation **PRINTING** ColorGraphics – Los Angeles, California



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