Chevron

2018 annual report

human energy®

140 years of human progress

leading the future of energy

Chevron delivers the affordable, reliable and ever-cleaner energy that enables human progress. As the energy landscape continues to evolve, Chevron invests in technology to push energy's frontiers. We mobilize our human ingenuity to solve the most complex challenges and leverage our financial strength to explore new possibilities.

Global demand for our products is growing, and Chevron's portfolio continues to grow stronger and more resilient. Our Upstream organization finds, develops and produces oil and gas resources efficiently. Our Downstream & Chemicals organization drives earnings across the value chain and grows our chemical and lubricant portfolios. Our Midstream business provides safe and reliable infrastructure and services, ensuring the safe movement of our finished products.

Of course, our greatest asset is our people. We are solvers of complex problems, and our global team — which includes engineers, scientists, environmentalists and technologists — is committed to leading the future of energy:

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

100 million metric tons

of carbon dioxide is expected to be injected into the Dupuy Formation over the life of the Gorgon facility*

*The Gorgon Carbon Dioxide Injection Project is the world's largest commercial-scale carbon dioxide injection facility of its kind, designed to reduce greenhouse gas emissions from the Gorgon Field project by approximately 40 percent.

On this page: Two of Chevron's Asia-class liquefied natural gas (LNG) vessels, docked at the Chevron-operated Gorgon project on Barrow Island, Western Australia. Each vessel will take on approximately 158,000m^3 of LNG, followed by a 10-day voyage to customers in Asia.

On the cover: Early morning at Tengiz, one of the world's deepest producing supergiant oil fields, a welder from local Kazakhstani company MontazhSpetsStroy completes the ground assembly for tank construction for the Future Growth Project and Wellhead Pressure Management Project (FGP-WPMP). As the next phase of expansion at Tengiz, FGP-WPMP is expected to increase production to ~1 million barrels per day.

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Gorgon and Wheatstone LNG projects play a key role in meeting the Asia-Pacific region's demand for affordable, reliable and ever-cleaner energy.

4.2 billion cubic feet/day

total production capacity of natural gas for Gorgon and Wheatstone

10 LNG carriers

Chevron's shipbuilding and fleet modernization program

24.5 million metric tons

total installed liquefaction capacity per year for Gorgon and Wheatstone

A digital version of this report is available:
www.chevron.com/annualreport2018

to our stockholders

This year marks Chevron's 140th anniversary — a milestone that prompts reflection on our history and admiration for the extraordinary women and men who have built a lasting company based on the belief that energy is vital to human progress.

This purpose is even clearer now than it was in 1879. Today, Chevron touches the lives of billions of people across the globe, delivering affordable, reliable, ever-cleaner energy that offers access to the necessities of modern life, drives economic and social development, and creates the promise for a better future.

We feel proud and privileged to fulfill this responsibility, to invest in the communities where we operate, and to generate sustained value for our stockholders, customers and employees.

Our strong performance in 2018 enabled us to deliver on all of our financial priorities — growing the dividend, funding a disciplined capital program, strengthening the balance sheet and returning surplus cash to stockholders.

Financial highlights from 2018 include:

net income

$14.8 billion

up $5.6 billion from 2017

capital employed

8.2% return

up from 5% in 2017

sales and other operating revenues

$158.9 billion

up $24.2 billion from 2017

record free cash flow

$16.8 billion

the highest level ever achieved by Chevron in any price environment

For the 31st consecutive year, Chevron increased the annual per-share dividend payout. We returned an additional $1.75 billion of cash to stockholders through stock repurchases. In addition, we further strengthened the balance sheet, reducing our debt ratio to 18 percent.

This performance reflects momentum across all our operating segments.

Our Upstream business reported a highest-ever worldwide net production of more than 2.9 million oil-equivalent barrels per day, up more than 7 percent from 2017 and 12 percent from 2016. Production increases were driven by Permian Basin growth, startups in the Gulf of Mexico and Australia, continued ramp-up of liquified natural gas (LNG) operations in Australia, and a high level of reliability at Tengizchevroil in Kazakhstan.

Permian Basin
Chevron and its legacy companies have been a fixture in the Permian Basin, which is located in the southwestern United States, since the early 1920s. In 2011, Chevron produced its 5 billionth barrel from the Permian. Today we are among the largest producers of oil and natural gas in the basin, and with approximately 2.2 million net acres (8,903 sq km), Chevron is one of the Permian Basin's largest net acreage holders.

We added approximately 1.46 billion barrels of net oil-equivalent proved reserves, replacing 136 percent of production. Our five-year reserve replacement ratio is 117 percent.

Chevron increased development drilling in the Permian Basin, and we expect continued strong production growth in the Permian over the next several years. We also acquired new exploration acreage, including six blocks in Brazil and 31 blocks in the Gulf of Mexico. Construction continued on the Future Growth Project and Wellhead Pressure Management Project in Kazakhstan, including first module delivery and installation.

In Downstream & Chemicals, we commissioned a new hydrogen plant as part of the Richmond Refinery Modernization Project. In our Oronite additives business, we broke ground on our blending and shipping project in Ningbo, China. Chevron Phillips Chemical Company commissioned its world-scale ethane cracker at the Cedar Bayou facility as part of the U.S. Gulf Coast Petrochemicals Project. We also expanded our new retail marketing network in Mexico, with 135 stations opened as of year-end 2018.

Our Midstream business delivered the first LNG cargo from the Gorgon project to the new LNG receiving terminal in Zhoushan, China, an important achievement that will help China meet its goal of increasing natural gas in its overall energy mix. In the Permian Basin, Chevron strategically secured pipeline capacity to maximize value in advance of our production ramp-up. Our Shipping organization supported the safe and successful delivery of the first modular component to the Future Growth Project in Kazakhstan — a voyage of nearly 17,000 miles.

Chevron delivered these results in a year characterized by healthy global economic activity and heightened geopolitical tensions. Global liquids demand surpassed 100 million barrels a day for the first time ever. Commodity prices rose during the first nine months of 2018, driven by strong demand, before declining in the last quarter. LNG markets continued to respond to strength in Asian gas demand. The return of U.S. sanctions on Iran, volatility in the Middle East, trade tensions between China and the United States, Russia sanctions, and worsening conditions in Venezuela created further uncertainty for global energy markets.

Although market conditions may remain volatile, our portfolio is resilient. We are focused on creating value through a disciplined capital program that prioritizes efficient, low-risk, short-cycle investments. Our Upstream portfolio is anchored by large, long-lived assets with low production decline. An efficient, high-return Downstream business complements our Upstream. Across all our business segments, we are accelerating the deployment of digital technologies to improve revenues, reduce costs, increase reliability and improve safety. We are making smart investments and building our company to win in any environment.

In 2018, we also had our best year ever in health, environment and safety performance, with no fatalities of employees or contractors in any of our operations. We continue to lead the industry in personal safety performance and meet or exceed targets on all core personal safety metrics. This performance is directly related to our strong Operational Excellence culture and an increased focus on safeguard assurance for high-risk work.

record safety

2018 marks our best year on record in health, environment and safety

In every instance, Chevron's performance rests on the strong foundation created by our people and our culture. The environment in which we operate is dynamic. The biggest questions of the future remain unanswered. Our work is complex and demanding. Yet for 140 years, the ingenuity of our people has led to new insights, new discoveries and new innovations.

This is not a coincidence. Our culture is defined by our values, which emphasize a deep commitment to diversity and inclusion, high performance, innovation, integrity, and trust. This has been part of our DNA for decades.

To hold ourselves to this high standard — and to ensure an effective approach to human capital management — we regularly seek employee feedback to understand where Chevron is performing well and where we can further improve. Our Board of Directors takes this input seriously — and we act on it. Based on feedback, we are working to Build Our Tomorrow, by putting new digital technologies in the hands of employees, promoting better, faster decision making and revamping our performance management system.

We use social media and other platforms to create access to information, remove organizational barriers, and bridge vast geographic expanses to exchange ideas and communicate. These are just some of the ways we put The Chevron Way to work, ensuring a culture in which all voices are heard, all ideas are considered and all our people have the opportunity to contribute to their fullest.

Actions like these are essential in today's environment. **But we recognize that leadership goes well beyond delivering strong financial returns and creating a compelling work experience. We must also deliver value for society.**

Our success is inextricably linked to the social progress and economic prosperity of the communities where we work. Our operations deliver good jobs and a better life. They promote the development of communities and enable the economic progress that fosters environmental improvement. In our annual *Corporate Responsibility Report,* available at www.chevron.com/cr, we highlight our performance in several environmental, social and governance areas.

Over the last five years, Chevron invested $154 billion in global goods and services and more than $1 billion in global social programs.

We are in the business of progress, and we cannot do this work alone. Across the countries where we operate, we rely on thousands of partners who help us convert our aspirations into real results. One such example is our support of the Global Fund and its work in Africa and the Pacific Rim fighting HIV/AIDS. In 2018, the Global Fund directed $2.5 million from Chevron to providing antiretroviral therapy to almost 20,000 people and helping reduce the mother-to-child transmission of HIV/AIDS. Since 2008, we have provided more than $60 million to the Global Fund, contributing to its success in saving more than 27 million lives.

We provide the affordable, reliable, ever-cleaner energy needed to meet rising demand. By 2040, the global population is expected to reach roughly 9 billion people, and the International Energy Agency expects global energy demand to increase by nearly 30 percent. Our strengths across Upstream, Midstream and Downstream position us to help meet society's growing need for energy.

We will meet this demand in a way that respects society's concerns about climate change and aspirations for a cleaner environment — views we share. This requires innovation. In 2018, we launched the $100 million Future Energy Fund, a venture capital fund established to invest in breakthrough technologies. Early investments include an electric vehicle charging network, novel battery technology and direct capture of carbon dioxide from the air.

We also joined the Oil and Gas Climate Initiative (OGCI), a coalition of 13 global companies cooperating on constructive actions to reduce greenhouse gas emissions.

OGCI CLIMATE INVESTMENTS

OIL AND GAS CLIMATE INITIATIVE

Our commitment includes a $100 million contribution to OGCI's more than $1 billion fund to invest in technologies and businesses that promise meaningful greenhouse gas emissions reductions.

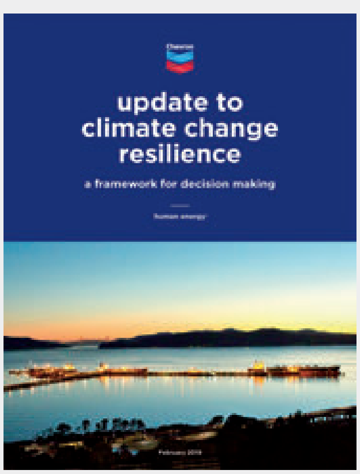
During my first year as chairman and CEO, I visited our operations around the world to listen to and learn from our employees. In my travels, I was often asked: "Why do you work for Chevron?" We work for our families. We work for our communities. We work to make the world a better place. And we work because we are proud of what we do.

I am honored to serve the women and men of Chevron. I am humbled by the opportunity to help build on our company's 140-year history and the work of generations of talented problem solvers who have turned some of the greatest challenges of our time into vast, human opportunities for advancement. I am proud, too, to represent a fundamental truth: energy enables human progress. I am committed to this truth, and I am fully confident that our people will continue to lead in the decades to come.

Sincerely,

Mike

Michael K. Wirth
Chairman of the Board and Chief Executive Officer
February 22, 2019



The greatest challenge we face is affordably and reliably meeting the energy needs of a growing world population and at the same time reducing emissions.

- In 2019, we updated Climate Change Resilience — *A Framework for Decision Making,* available at www.chevron.com/corporate-responsibility/climate-change, which explains our strategic approach as it relates to climate change, to enhance reporting on governance, risk management, strategy and actions. This report is consistent with the recommendations made by the Financial Stability Board's Task Force on Climate-Related Financial Disclosures.

- In 2019, we added a new metric to our corporate scorecard tied to reducing greenhouse gas emissions. Chevron's target is to achieve by 2023 a 20 to 25 percent reduction in methane emissions intensity and a 25 to 30 percent reduction in flaring intensity. Employee bonus compensation is tied to our performance on this scorecard.

winning in any environment

Every day, we focus on delivering the energy that enables human progress and the ways we can — and will — win in any environment. We are committed to business strategies to grow free cash flow, improve returns and deliver value to our stockholders.

To win in any environment, we must innovate.
Year after year, we will:

grow production and sustain margins

be returns-driven in capital allocation

lower our cost structure

get more out of assets

high-grade portfolio

Photo: Jack/St. Malo is Chevron's signature deepwater project in the U.S. Gulf of Mexico. Total daily production from Jack/St. Malo fields in 2018 averaged 139,000 barrels of liquids (71,000 net) and 21 million cubic feet of natural gas (11 million net). Mike Biondo, an Operations Team member, is shown here conducting routine checks on the floating production unit to ensure reliable and safe operations.

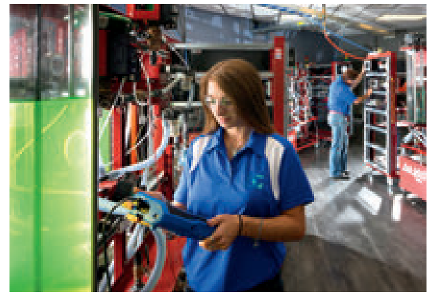
our sources of competitive advantage

expertise

We leverage nearly a century and a half of expertise to navigate global markets, thrive in diverse economies and cultures, operate in complex regulatory environments, and develop new energy solutions.

purpose

We are committed to delivering the energy that improves lives and enables human progress, within a company culture defined by trust, responsibility and integrity. Our purpose guides our aspirations, motivations and operations.



people

We invest in developing and deploying generations of problem solvers, and we equip them to solve today's biggest challenges while anticipating those on the horizon. We believe the greatest resources we have are human ingenuity, creativity and imagination.

partners

We partner around the world to deliver the energy of today and explore the energy opportunities of tomorrow. Delivering energy — from exploration to extraction to production to distribution — requires a network of trusted partners who succeed when we succeed.

technology

We leverage technology to push energy's frontiers. Every day, we scan the landscape for opportunities to make the world's energy cleaner and more affordable, our environmental footprint smaller, and the industry's workforce safer.

financial strength

Our financial strength supports our goal to invest in future opportunities and deliver sustained shareholder value in any economic environment. We put our financial strength to work to shape the future of energy — identifying the most promising trends, making smart investments and scaling the most sustainable solutions on a global basis.

assets

We have diversified, high-quality assets around the world that underpin our financial strength and present opportunities for future development.

energy is at the heart of everything we do

Our success is driven by our people and their commitment to getting results the right way — by operating responsibly, executing with excellence, applying innovative technologies and capturing new opportunities for profitable growth.

our leadership

engaged leaders are working to mobilize chevron's human ingenuity to solve the most complex energy challenges

As a company that touches the lives of billions of people around the world and provides the necessities of modern life, our responsibilities are profound. Today, employees, partners, customers and investors expect more from the corporation and its Board of Directors than ever before.

The Chevron Board not only guides enterprise direction, but also continuously assesses internal and external views on a variety of topics, from energy market conditions and geopolitical developments to technology trends and competitor actions. Our Board has a proven track record across a broad range of experiences, including leadership of global businesses and international affairs; expertise in science, technology and engineering; extensive knowledge of governmental, regulatory, legal, environmental and public policy issues; and complex financial management, capital allocation and reporting processes.

Diversity of gender, ethnicity, age, skills and experience fosters the different perspectives that make our Board's oversight and decision making more effective.

The Chevron Board meets six times a year, often including field visits that provide insight into our human capital and operations. In 2018, the Board visited Argentina for an in-depth look at Chevron's efforts to advance the development of Vaca Muerta — one of the largest deposits of shale oil and gas in the world — and support our company's continued investment and commitment to economic growth in the area. During the visit, the Board met with members of the Argentine government and spent a day at Loma Campana, the flagship shale development in Vaca Muerta.

These visits help the Board establish a deeper connection to the business by offering opportunities to listen to, learn from and engage with the employees and partners who are leading the future of energy.

lead director: one-on-one

independent lead director ronald d. sugar discusses several key areas in which chevron is committed to lead — the future of energy, human capital management, stockholder engagement and board diversity

Q: How does the diverse background of Chevron's Board help the company navigate the world's energy transition?

A: For more than a century and a half, the world has been in an energy transition as the first and second industrial revolutions have mechanized production, agriculture and other aspects of modern life. These advances have been fueled by energy as a primary input, and they set humanity on a track to continuously seek more affordable, reliable and ever-cleaner energy inputs in order to meet increasing global demand created by a growing population and ambitions for prosperity.

The diverse experience and expertise of Chevron's Board play a critical role in helping the company navigate the challenges and opportunities of this transition. By bringing together unique skills and qualifications developed through leadership in academia, business, finance and technology, as well as a diversity of gender, age, background and ethnicity, the Board is well positioned to test company strategy on an ongoing basis. As part of our duty to provide robust oversight, the Board also meets with external experts to add new perspectives regarding the evolving energy landscape. Through these efforts, the Board continuously drives Chevron's strategy and ensures that risks are understood and mitigated.

Q: Tell us more about the Board's role in human capital management.

A: Our Board is highly focused on human capital management issues, reflecting our belief that Chevron's greatest resources are human ingenuity and sense of purpose. To ensure an engaged and inclusive work environment that values safety, The Chevron Way, and diversity of our employees' talents and experiences, the Board reviews and approves executive compensation, executive selections and succession plans, and diversity and inclusion data. We regularly meet with employees at all levels and in different locations to observe firsthand how our investments in human capital are succeeding.

Q: What were the key takeaways from meetings with stockholders in 2018?

A: An engagement team of Chevron officers and experts held productive meetings with stockholders in 2018 to discuss a variety of topics — from financial performance to environmental, social and governance matters. I participated in some of these engagements. Our investors took a strong interest in three areas: managing risks associated with climate change; ensuring transparency of lobbying practices and processes; and having more insight into human capital management.

We are taking important actions in response to this dialogue. In February 2019, we announced new methane and flaring intensity reduction targets as we updated key sections of *Climate Change Resilience — A Framework for Decision Making*. We also took steps to provide more transparency in our lobbying activities by lowering the disclosure threshold — from $500,000 to $100,000 in annual dues — for trade association memberships wherein a portion of our dues may be used for lobbying purposes. And we are committed to more disclosure in our annual *Corporate Responsibility Report* on issues such as gender equity, employee well-being, and recruitment and retention.

Q: How important is Board refreshment and evaluation?

A: To understand and lead in a dynamic energy market, it is important that we constantly evolve, including the membership of our Board. We have experienced meaningful refreshment in recent years, resulting in average Board tenure of 4.7 years, with a range from less than one year to 14 years. Our Directors must have broad experience and expertise relevant to the changing needs of the company and our industry.

To enable Board refreshment and regular rotation of Committee chairs, Directors are elected annually and serve for a one-year term or until their successors are elected. In addition, every year, the Board and its Committees conduct a comprehensive self-evaluation, and I lead a discussion of the results with the full Board. This year, we augmented our evaluation process to make evaluations of individual Director performance more rigorous.

Our Board is highly focused on human capital management issues, reflecting our belief that Chevron's greatest resources are human ingenuity and sense of purpose.

board of directors

The Board of Directors of Chevron directs the affairs of the corporation and is committed to sound principles of corporate governance. The Directors bring a proven track record of success across a broad range of experiences at the policymaking level.

Michael K. (Mike) Wirth, 58

Chairman of the Board and Chief Executive Officer since February 2018. He was elected to these positions by Chevron's Independent Directors in September 2017 and assumed the roles on February 1, 2018. Prior to his current role, Wirth served as vice chairman of the Board in 2017 and executive vice president of Midstream and Development for Chevron Corporation from 2016 to 2018. In that role, he was responsible for supply and trading, shipping, pipeline, and power operating units; corporate strategy; business development; and policy, government and public affairs.

Wirth was executive vice president of Downstream & Chemicals from 2006 to 2015. Prior to that, he served as president of Global Supply and Trading from 2003 to 2006. In 2001, Wirth was named president of Marketing for Chevron's Asia/Middle East/Africa business, based in Singapore. He also served on the board of directors for Caltex Australia Limited and GS Caltex Corporation in South Korea.

Wirth serves on the board of directors of Catalyst. He also serves on the board of directors and executive committee of the American Petroleum Institute and is a member of the National Petroleum Council, the Business Roundtable, the World Economic Forum International Business Council and the American Society of Corporate Executives. Wirth joined Chevron in 1982 as a design engineer. He earned a bachelor's degree in chemical engineering from the University of Colorado in 1982.

Wanda M. Austin, 64

Director since 2016. She is interim president at the University of Southern California, and she holds an adjunct Research Professor appointment at the University of Southern California's Viterbi School's Department of Industrial and Systems Engineering. She is a retired 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, 62

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 of Oaktree Strategic Income Corporation. (1)

Alice P. Gast, 60

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., 63

Director since 2008. He is chairman and chief executive officer 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. (3, 4)

Charles W. Moorman IV, 67

Director since 2012. He is a 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 also a retired president and chief executive officer of Amtrak, a passenger rail service provider. He is a director of Duke Energy Corporation and Oracle Corporation. (1)

Dambisa F. Moyo, 50

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 3M Company and Barclays plc. (1)

Debra Reed-Klages, 63

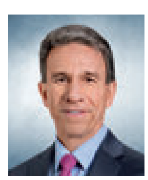
Director since 2018. She is a retired chairman, chief executive officer and president of Sempra Energy, an energy-services holding company in North America and South America. Previously, she was executive vice president of Sempra Energy and president and chief executive officer of San Diego Gas & Electric and Southern California Gas Co. She is a director of Caterpillar Inc. (3,4)

Ronald D. Sugar, 70

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; Bain & Company; Temasek Americas Advisory Panel, based in Singapore; and the G100 Network and the World 50. He is a director of Air Lease Corporation, Amgen Inc. and Apple Inc. (2, 3)

Inge G. Thulin, 65

Director since 2015. He is executive chairman of the board of 3M Company, a diversified global manufacturer, technology innovator, and marketer of a variety of products and services. Previously, he was chairman, president and chief executive officer of 3M. Prior to that, he was the company's executive vice president and chief operating officer. He is a director of Merck & Co. (1)



D. James Umpleby III, 61

Director since 2018. He is chairman and 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. (2, 3)

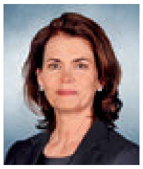
Committees of the Board

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: Wanda M. Austin, Chair

corporate officers

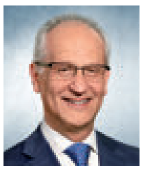
Pierre R. Breber, 54

Vice President and Chief Financial Officer since 2019. Responsible for comptroller, tax, treasury, audit and investor relations. Previously, executive vice president, Downstream & Chemicals, and executive vice president, Gas and Midstream. Joined the company in 1989.



Mary A. Francis, 54

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. Joined the company in 2002.



Joseph C. Geagea, 59

Executive Vice President, Technology, Projects and Services, since 2015. Responsible for energy technology; delivery of major capital projects; procurement; Information and Technology; Health, Environment and Safety; talent selection; and business development. Previously, senior vice president, Technology, Projects and Services. Joined the company in 1982.

James W. Johnson, 60

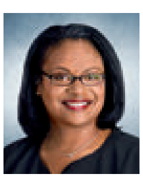
Executive Vice President, Upstream, since 2015. Responsible for Chevron's global exploration and production activities for crude oil and natural gas. Previously, senior vice president, Upstream; president, Chevron Europe, Eurasia and Middle East Exploration and Production Company; managing director, Eurasia business unit; and managing director, Australasia business unit. Joined the company in 1981.

Charles N. Macfarlane, 64

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.

Navin K. Mahajan, 52

Vice President and Treasurer since 2019. Responsible for Chevron's banking, financing, cash management, insurance, pension investments, and credit and receivables activities. Previously, vice president of finance for Chevron's Downstream & Chemicals organization, assistant treasurer of OpCo Financing for Chevron, and chief compliance officer. Joined the company in 1996.



Rhonda J. Morris, 53

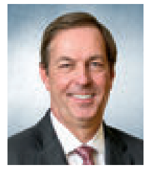
Vice President since 2016 **and Chief Human Resources Officer** since 2019. Responsible for human resources, diversity, ombuds, and global health and medical groups. Previously, vice president, Human Resources, Downstream & Chemicals. Joined the company in 1991.

Mark A. Nelson, 55

Executive Vice President, Downstream & Chemicals, since 2019. 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, vice president, Midstream, Strategy and Policy, and vice president, Strategic Planning. Joined the company in 1985.

Executive Committee

Michael K. Wirth, Pierre R. Breber, Joseph C. Geagea, James W. Johnson, Mark A. Nelson, Colin E. Parfitt, R. Hewitt Pate and Rhonda J. Morris.



Bruce Niemeyer, 57

Vice President, Strategic Planning, since 2018. Responsible for the company's strategic direction, allocation of resources, and determination of performance measures and targets. Previously, vice president of Chevron's Mid-Continent business unit and vice president of the Appalachian/Michigan Strategic business unit. Joined the company in 2000.

Jeanette L. Ourada, 53

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; assistant treasurer; and general manager, Investor Relations. Joined the company in 2004.

Colin E. Parfitt, 55

Vice President, Midstream, since 2019. Responsible for Chevron's Midstream business, including the company's supply and trading, shipping, pipeline, and power operating units. Previously, president, Supply and Trading. Joined the company in 1995.

R. Hewitt Pate, 56

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.

J. David (Dave) Payne, 58

Vice President, Health, Environment and Safety (HES), since 2018. Responsible for HES strategic planning and issues management, compliance assurance, and emergency response. Previously, vice president of Drilling and Completions. Prior to that, drilling manager in Bangkok. Joined the company in 1981.

Jay R. Pryor, 61

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.

Dale A. Walsh, 60

Vice President, Corporate Affairs, since 2019. Responsible for anticipating and responding to changing stakeholder expectations and managing social, political and reputational risks. Previously, president, Americas Products from 2010, and president, Lubricants, 2006–2010. Joined the company in 1983.

Retiring Officers

Wesley E. Lohec, retired effective June 2018; vice president, Health, Environment and Safety, since 2011; joined the company in 1981. **Joseph M. Naylor,** retired effective April 2019; vice president, Policy, Government and Public Affairs, since 2016; joined the company in 1982. **Randolph S. (Randy) Richards,** retired effective February 2019; vice president and treasurer since 2016; joined the company in 1979. **Patricia E. Yarrington,** retired effective April 2019; vice president and chief financial officer since 2009; joined the company in 1980.

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.

Photo: The Mafumeira Sul project off the coast of Cabinda province in Angola is part of a continuing effort to grow Chevron's production capacity in offshore Block 0 and contribute to the development of Angola's oil and gas industry. First liquified petroleum gas export began in January 2018. Ramp-up continued at the main production facility, with total daily production in 2018 averaging 52,000 barrels of liquids (17,000 net) and 147 million cubic feet of natural gas (57 million net) exported to the Angola LNG plant. Every day, employees at Mafumeira Sul like the ones shown here are committed to protecting people and the environment.

net oil-equivalent daily production[1]

2.9 million barrels

sales and other operating revenues[1]

$158.9 billion

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 proved reserves[2,3]

12.1 billion barrels

total assets[2]

$253.9 billion

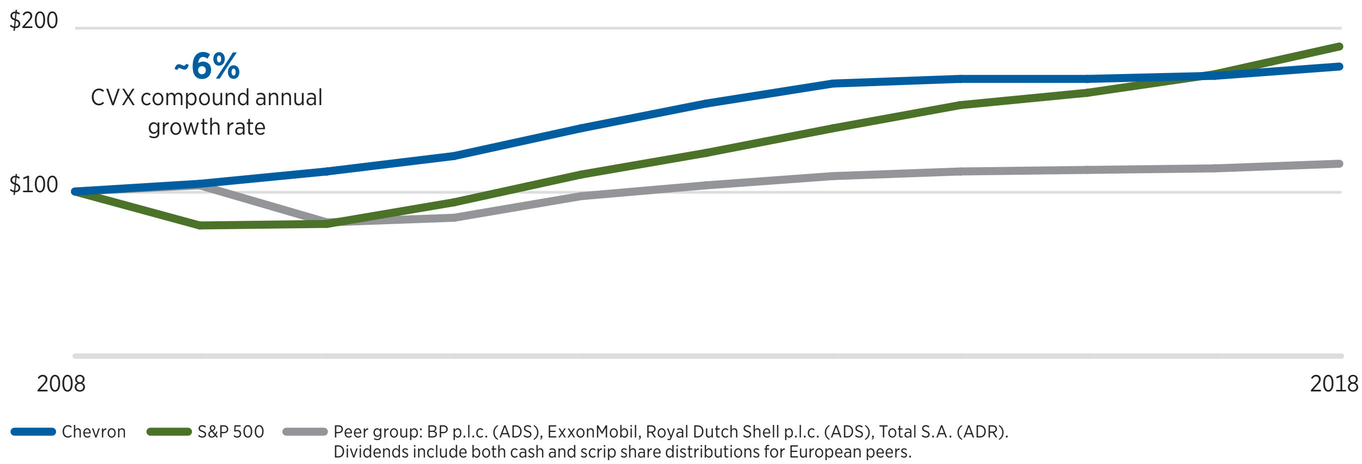
1 Year ended December 31, 2018
2 At December 31, 2018
3 For definition of "reserves," see glossary of energy and financial terms, page 103

chevron stock performance

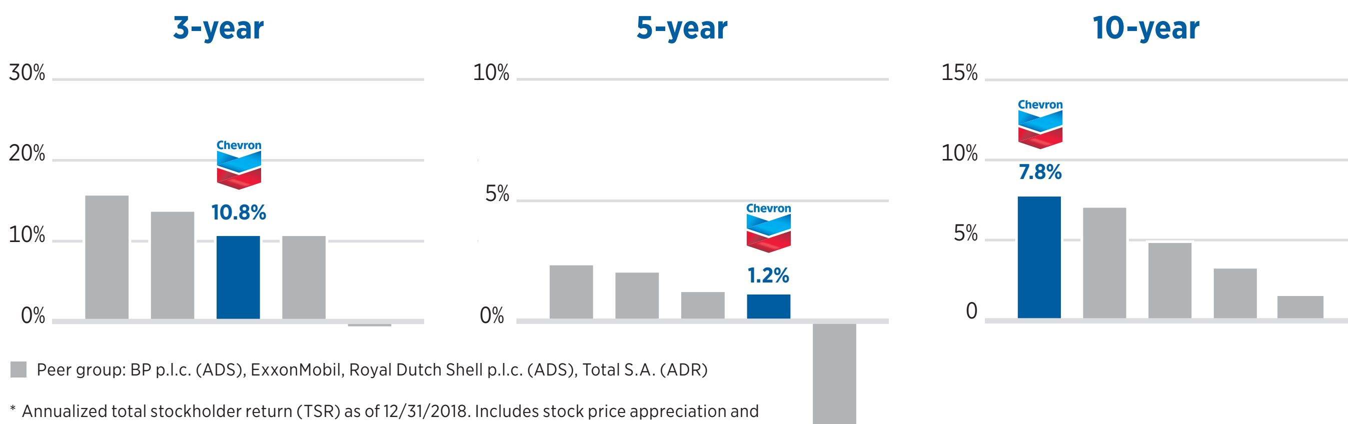
31 consecutive years

2018 marked the 31st consecutive year we increased
the annual per-share dividend payout

Indexed dividend growth
Basis 2008 = 100



Total stockholder returns*
(as of 12/31/2018)

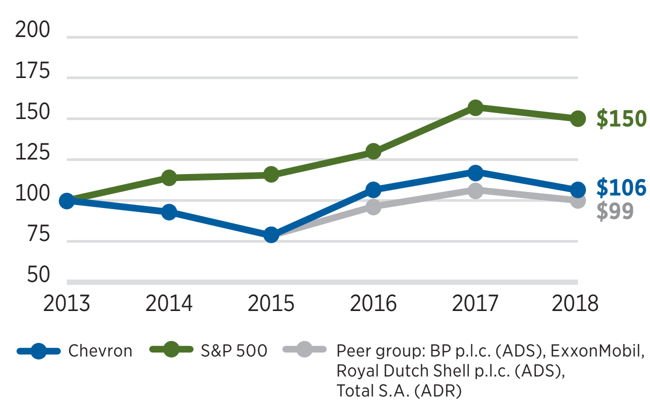


Peer group: BP p.l.c. (ADS), ExxonMobil, Royal Dutch Shell p.l.c. (ADS), Total S.A. (ADR)

* Annualized total stockholder return (TSR) as of 12/31/2018. 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, 2013, and ending December 31, 2018, 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 have been entitled to receive and is adjusted for stock splits. The interim measurement points show the value of $100 invested on December 31, 2013, as of the end of each year between 2014 and 2018.

Five-year cumulative total returns
(Calendar years ended December 31)

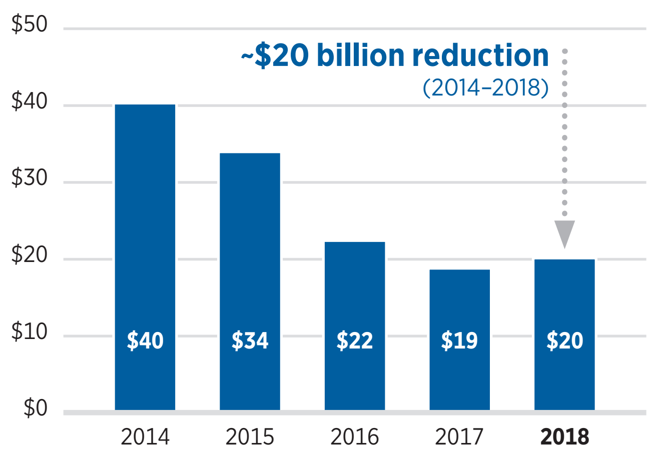


financial and operating highlights

Financial highlights[1]	2018	2017	2016
Net income (loss) attributable to Chevron Corporation	**$ 14,824**	$ 9,195	$ (497)
Sales and other operating revenues	**$ 158,902**	$ 134,674	$ 110,215
Cash provided by operating activities[2]	**$ 30,618**	$ 20,338	$ 12,690
Capital and exploratory expenditures[3]	**$ 20,106**	$ 18,821	$ 22,428
Total assets at year-end	**$ 253,863**	$ 253,806	$ 260,078
Total debt and capital lease obligations at year-end	**$ 34,459**	$ 38,763	$ 46,126
Chevron Corporation stockholders' equity at year-end	**$ 154,554**	$ 148,124	$ 145,556
Common shares outstanding at year-end (Thousands)	**1,888,670**	1,890,534	1,877,338
Per-share data			
Net income (loss) attributable to Chevron Corporation — diluted	**$ 7.74**	$ 4.85	$ (0.27)
Cash dividends	**$ 4.48**	$ 4.32	$ 4.29
Chevron Corporation stockholders' equity	**$ 81.83**	$ 78.35	$ 77.53
Common stock price at year-end	**$ 108.79**	$ 125.19	$ 117.70
Debt ratio	**18.2%**	20.7%	24.1%
Return on stockholders' equity	**9.8%**	6.3%	(0.3)%
Return on capital employed	**8.2%**	5.0%	(0.1)%

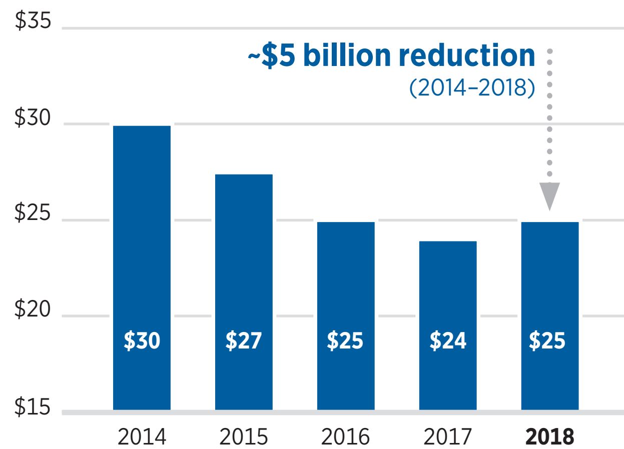
[1] Millions of dollars, except per-share amounts
[2] 2017 and 2016 adjusted to conform to Accounting Standards Updates 2016–15 and 2016–18
[3] Includes equity in affiliates

Total capital and exploratory expenditures[4]
($ - Billions)



[4] Includes expenditures by equity affiliates

Operating expense[5]
($ - Billions)



[5] Includes operating expense, selling, general and administrative expense, and other components of net periodic benefit costs

Operating highlights[6]	2018	2017	2016
Net production of crude oil, condensate, NGLs and synthetic oil[7] (Thousands of barrels per day)	**1,782**	1,723	1,719
Net production of natural gas (Millions of cubic feet per day)	**6,889**	6,032	5,252
Total net oil-equivalent production (Thousands of oil-equivalent barrels per day)	**2,930**	2,728	2,594
Net proved reserves of crude oil, condensate, NGLs and synthetic oil[7,8] (Millions of barrels)	**6,790**	6,542	6,328
Net proved reserves of natural gas[8] (Billions of cubic feet)	**31,576**	30,736	28,760
Net proved oil-equivalent reserves[8] (Millions of barrels)	**12,053**	11,665	11,121
Refinery input (Thousands of barrels per day)	**1,608**	1,661	1,688
Sales of refined products (Thousands of barrels per day)	**2,655**	2,690	2,675
Number of employees at year-end[9]	**45,047**	48,596	51,953

[6] Includes equity in affiliates, except number of employees
[7] NGLs = natural gas liquids
[8] At year-end
[9] Excludes service station personnel

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: Startup of the new ethane cracker was achieved at the Chevron Phillips Chemical Company LLC's (CPChem) U.S. Gulf Coast Petrochemical Project in March 2018. CPChem's strong positions in North America and the Middle East enable it to leverage the availability of competitive feedstocks to meet growing global demand.

Financial Table of Contents

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

Consolidated Financial Statements

Notes to the Consolidated Financial Statements

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," "will," "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 the company's control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets or shares or the delay or failure of such transactions to close based on required closing conditions; the potential for gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, tariffs, sanctions, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; material reductions in corporate liquidity and access to debt markets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; the company's ability to identify and mitigate the risks and hazards inherent in operating in the global energy industry; and the factors set forth under the heading "Risk Factors" on pages 18 through 21 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

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

Earnings by Major Operating Area

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

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

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

Business Environment and Outlook

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

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

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

Refer to the "Cautionary Statement Relevant to Forward-Looking Information" on page 2 and to "Risk Factors" in Part I, Item 1A, on pages 18 through 21 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. Asset dispositions and restructurings may result in significant gains or losses in future periods. The company's asset sale program for 2018 through 2020 is targeting before-tax proceeds of $5-10 billion. Proceeds related to asset sales were $2.0 billion in 2018.

The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of movements in prices for crude oil and natural gas. Management takes these developments into account in the conduct of daily operations and for business planning.

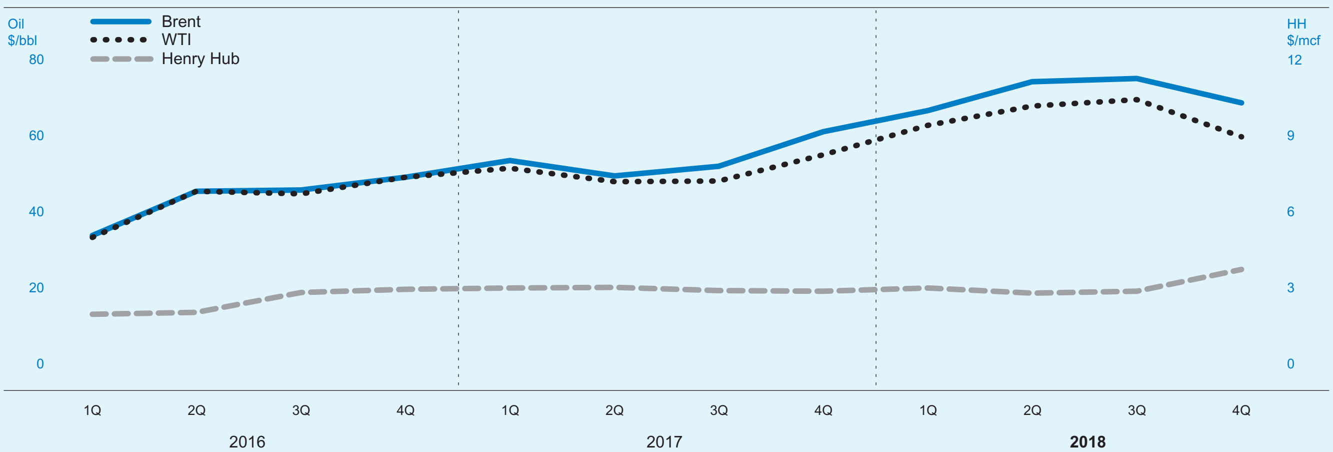
Comments related to earnings trends for the company's major business areas are as follows:

Upstream Earnings for the upstream segment are closely aligned with industry prices for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry production and inventory levels, technology advancements, production quotas or other actions imposed by the Organization of Petroleum Exporting Countries (OPEC) or other producers, actions of regulators, weather-related damage and disruptions, competing fuel prices, and regional supply interruptions or fears thereof that may be caused by military conflicts, civil unrest or political uncertainty. Any of these factors could also inhibit the company's production capacity in an affected region. The company closely monitors developments in the countries in which it operates and holds investments, and seeks to manage risks in operating its facilities and businesses. The longer-term trend in earnings for the upstream segment is also a function of other factors, including the company's ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms of contracts, and changes in tax and other applicable laws and regulations.

The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. However, price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can be subject to external factors beyond the company's control including, among other things, the general level of inflation, tariffs or other taxes imposed on goods or services, commodity prices and prices charged by the industry's material and service providers, which can be affected by the volatility of the industry's own supply-and-demand conditions for such materials and services. Modest cost pressures continue in rig-related services across North America unconventional markets. Cost pressures have softened in well completion activity particularly in the Permian Basin, but are expected to rise when pipeline takeaway constraints are resolved in late 2019. International and offshore markets are showing indications of increased activity levels with limited cost pressures to date.

Capital and exploratory expenditures and operating expenses could also be affected by damage to production facilities caused by severe weather or civil unrest, delays in construction, or other factors.

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 majority of the company's equity crude production is priced based on the Brent benchmark. The Brent price averaged $71 per barrel for the full-year 2018, compared to $54 in 2017. Crude oil prices increased throughout the first three quarters of 2018 due to solid demand combined with OPEC production cuts. Late in the year, continued U.S. shale growth, combined with unexpected short-term waivers from Iranian sanctions granted to several countries, led to excess supply conditions, resulting in a decrease in oil prices. In response, OPEC agreed to new production cuts in early December. As of mid-February 2019, the Brent price was $64 per barrel.

The WTI price averaged $65 per barrel for the full-year 2018, compared to $51 in 2017. WTI traded at a discount to Brent throughout 2018. Differentials to Brent have ranged between $3 to $10 in 2018 primarily due to pipeline infrastructure constraints which have restricted flows on the inland crude to export outlets on the Gulf Coast, in addition to variability in other factors impacting supply and demand of each benchmark crude. As of mid-February 2019, the WTI price was $54 per barrel.

Chevron has interests in the production of heavy crude oil in California, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page 37 for the company's average U.S. and international crude oil sales prices.)

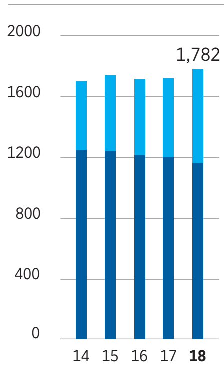
In contrast to price movements in the global market for crude oil, price changes for natural gas are more closely aligned with supply-and-demand conditions in regional markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged $3.12 per thousand cubic feet (MCF) during 2018, compared with $2.97 during 2017. As of mid-February 2019, the Henry Hub spot price was $2.61 per MCF.

Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. Chevron sells natural gas into the domestic pipeline market in many locations. In some locations, Chevron has invested in long-term projects to produce and liquefy natural gas for transport by tanker to other markets. The company's long-term contract prices for liquefied natural gas (LNG) are typically linked to crude oil prices. Most of the equity LNG offtake from the operated Australian LNG projects is committed under binding long-term contracts, with the remainder to be sold in the Asian spot LNG market. The Asian spot market reflects the supply and demand for LNG in the Pacific Basin and is not directly linked to crude oil prices. International natural gas realizations averaged $6.29 per MCF during 2018, compared with $4.62 per MCF during 2017. (See page 37 for the company's average natural gas realizations for the U.S. and international regions.)

The company's worldwide net oil-equivalent production in 2018 averaged 2.930 million barrels per day. About one-sixth of the company's net oil-equivalent production in 2018 occurred in the OPEC-member countries of Angola, Nigeria, Republic of Congo and Venezuela. OPEC quotas had no effect on the company's net crude oil production in 2018 or 2017.

The company estimates that net oil-equivalent production in 2019 will grow 4 to 7 percent compared to 2018, assuming a Brent crude oil price of $60 per barrel and excluding the impact of anticipated 2019 asset sales. This estimate is subject to many factors and uncertainties, including quotas or other actions that may be imposed by OPEC; price effects on entitlement volumes; changes in fiscal terms or restrictions on the scope of company operations; delays in construction; reservoir performance; greater-than-expected declines in production from mature fields; start-up or ramp-up of projects; fluctuations in demand for natural gas in various markets; weather conditions that may shut in production; civil unrest; changing geopolitics; delays in completion of maintenance turnarounds; or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and the time lag between initial exploration and the beginning of production. The company has increased its investment emphasis on short-cycle projects.

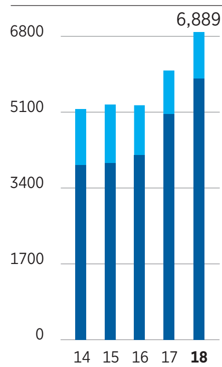
Net liquids production*
Thousands of barrels per day



United States
International

* Includes equity in affiliates.

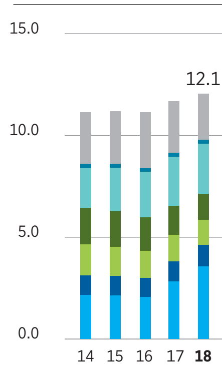
Net natural gas production*
Millions of cubic feet per day



United States
International

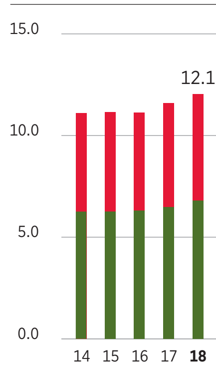
* Includes equity in affiliates.

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 2019, production remains shut in and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait. The financial effects from the loss of production in 2018 were not significant and are not expected to be significant in 2019.

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

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

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

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

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

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

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

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

Operating Developments

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

Upstream

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

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

Downstream

South Africa and Botswana Completed the sale of refining, marketing and lubricant assets.

United States Chevron Phillips Chemical Company LLC (CPChem), the company's 50 percent-owned affiliate, commenced operations of a new ethane cracker at its Cedar Bayou facility in Baytown, Texas.

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

Other

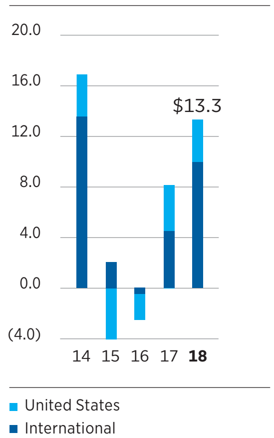
Common Stock Dividends The 2018 annual dividend was $4.48 per share, making 2018 the 31st consecutive year that the company increased its annual per share dividend payout. In January 2019, the company's Board of Directors approved a $0.07 per share increase in the quarterly dividend to $1.19 per share,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

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

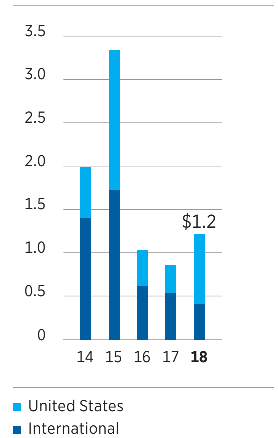
Results of Operations

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

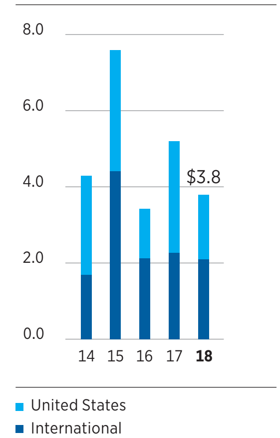
Worldwide Upstream earnings
Billions of dollars



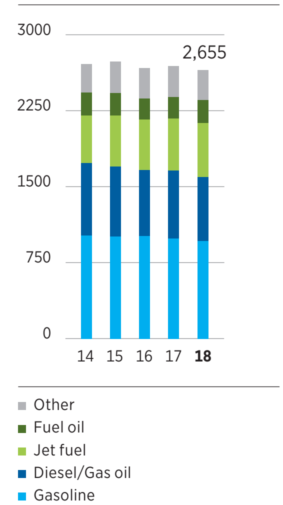
Exploration expenses
Billions of dollars (before-tax)



Worldwide Downstream earnings
Billions of dollars



Worldwide refined product sales
Thousands of barrels per day



U.S. Upstream

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

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

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

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

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

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

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

International Upstream

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

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

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

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

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

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

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

U.S. Downstream

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

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

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

Total refined product sales of 1.22 million barrels per day in 2018 were up 2 percent from 2017. Sales were 1.20 million barrels per day in 2017, a decrease of 1 percent from 2016, primarily due to the divestment of Hawaii refining and marketing assets in fourth quarter 2016.

Refer to the "Selected Operating Data" table on page 37 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

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

International downstream earned $1.70 billion in 2018, compared with $2.28 billion in 2017. The decrease in earnings was largely due to lower margins on refined product sales of $590 million and lower gains on asset sales of $470 million, partially offset by lower operating expenses of $290 million. The sale of the company's Canadian refining and marketing business in third quarter 2017 and the sale of the southern Africa refining and marketing business in third quarter 2018 primarily contributed to the lower margins and operating expenses. Foreign currency effects had a favorable impact on earnings of $161 million between periods.

International downstream earned $2.28 billion in 2017, compared with $2.13 billion in 2016. The increase in earnings was primarily due to higher gains on asset sales of $360 million, partially offset by higher operating expenses of $140 million. Foreign currency effects had an unfavorable impact on earnings of $65 million between periods.

Total refined product sales of 1.44 million barrels per day in 2018 were down 4 percent from 2017, primarily due to the sales of the company's Canadian refining and marketing assets in third quarter 2017 and southern Africa refining and marketing business in third quarter 2018. Sales of 1.49 million barrels per day in 2017 were up 2 percent from 2016, primarily due to higher diesel and jet fuel sales.

Refer to the "Selected Operating Data" table on page 37, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

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

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

Net charges in 2018 decreased $1.88 billion from 2017. The change between periods was mainly due to absence of a prior year tax charge of $2.47 billion related to U.S. tax reform, lower employee expenses and the absence of a reclamation related charge for a former mining asset, partially offset by other unfavorable tax items and higher interest expense. Foreign currency effects increased net charges by $105 million between periods. Net charges in 2017 increased $2.77 billion from 2016, mainly due to higher tax items, primarily reflecting a $2.47 billion expense from U.S. tax reform, higher interest expense and a reclamation related charge for a former mining asset, partially offset by lower employee expense. Foreign currency effects decreased net charges by $139 million between periods.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

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

Sales and other operating revenues increased in 2018 mainly due to higher crude oil, refined product and natural gas prices. The increase between 2017 and 2016 was primarily due to higher refined product and crude oil prices, higher crude oil volumes, and higher natural gas volumes.

Beginning in 2018, excise, value-added and similar taxes collected on behalf of third parties were no longer included in "Sales and other operating revenue", but were netted in "Taxes other than on income" in accordance with ASU 2014-09. 2017 and 2016 include $7.19 billion and $6.91 billion, respectively, in taxes collected on behalf of third parties.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The increase in income tax expense in 2018 of $5.76 billion is due to the increase in total income before tax for the company of $11.35 billion and the absence of the remeasurement benefits from U.S. tax reform recognized in 2017.

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

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

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

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

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

Selected Operating Data[1,2]

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

1 Includes company share of equity affiliates.

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

3 Includes natural gas consumed in operations (MMCFPD):

	2018	2017	2016
United States	**35**	37	54
International	**584**	528	432

4 Includes net production of synthetic oil:

	2018	2017	2016
Canada	**53**	51	50
Venezuela affiliate	**24**	28	28

5 Includes branded and unbranded gasoline.

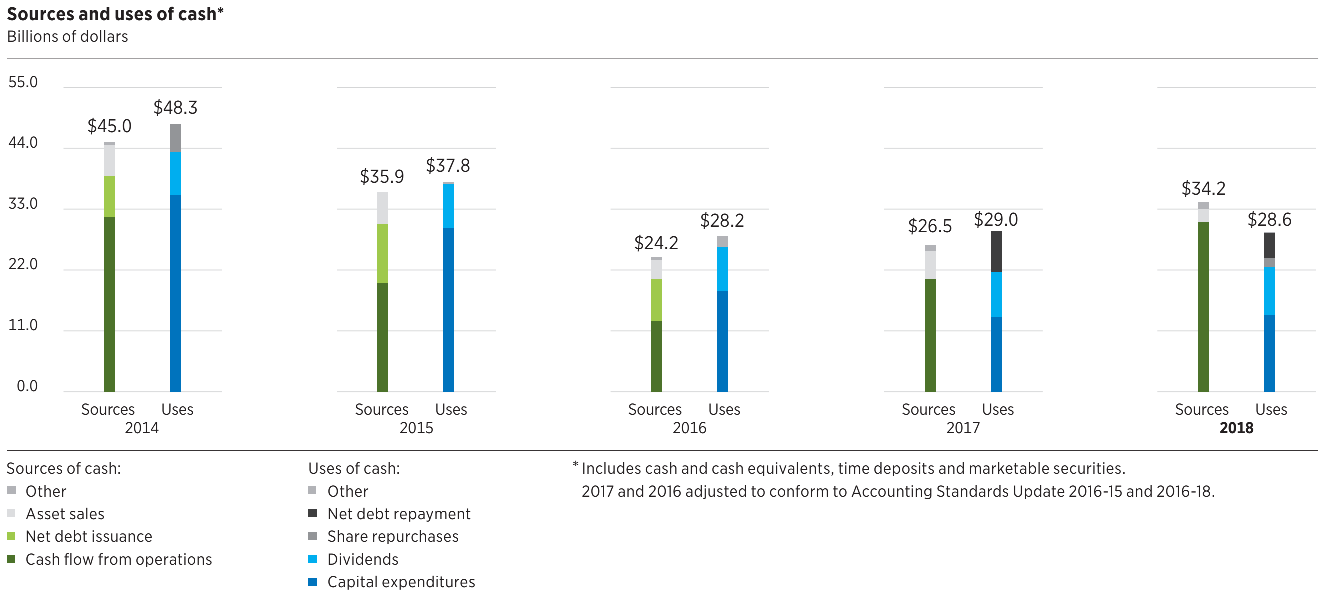
6 In November 2016, the company sold its interests in the Hawaii Refinery, which included operable capacity of 54,000 barrels per day.

7 Includes sales of affiliates (MBPD): **373** 366 377

8 In September 2018, the company sold its interest in the Cape Town Refinery in Cape Town, South Africa, which had an operable capacity of 110,000 barrels per day. In September 2017, the company sold the Burnaby Refinery in British Columbia, Canada, which had operable capacity of 55,000 barrels per day.

Liquidity and Capital Resources

Sources and uses of cash



The strength of the company's balance sheet enabled it to fund any timing differences throughout the year between cash inflows and outflows.

Cash, Cash Equivalents, Marketable Securities and Time Deposits Total balances were $10.3 billion and $4.8 billion at December 31, 2018 and 2017, respectively. Cash provided by operating activities in 2018 was $30.6 billion, compared with $20.3 billion in 2017 and $12.7 billion in 2016, reflecting higher crude oil prices and increased production. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.0 billion in 2018, $1.0 billion in 2017 and $0.9 billion in 2016. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.0 billion in 2018, $4.9 billion in 2017 and $3.2 billion in 2016.

Restricted cash of $1.1 billion and $1.1 billion at December 31, 2018 and 2017, respectively, was held in cash and short-term marketable securities and recorded as "Deferred charges and other assets" and "Prepaid expenses and other current assets" on the Consolidated Balance Sheet. These amounts are generally associated with upstream abandonment activities, tax payments, funds held in escrow for tax-deferred exchanges and refundable deposits related to pending asset sales.

Dividends Dividends paid to common stockholders were $8.5 billion in 2018, $8.1 billion in 2017 and $8.0 billion in 2016.

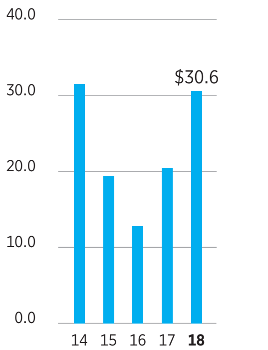
Debt and Capital Lease Obligations Total debt and capital lease obligations were $34.5 billion at December 31, 2018, down from $38.8 billion at year-end 2017.

The $4.3 billion decrease in total debt and capital lease obligations during 2018 was primarily due to the repayment of long-term notes totaling $6.7 billion as they matured during 2018, partly offset by an increase in commercial paper. The company's debt and capital lease obligations due within one year, consisting primarily of commercial paper, redeemable long-term obligations and the current portion of long-term debt, totaled $15.6 billion at December 31, 2018, compared with $15.2 billion at year-end 2017. Of these amounts, $9.9 billion and $10.0 billion were reclassified to long-term debt at the end of 2018 and 2017, respectively.

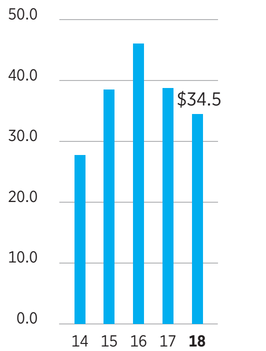
At year-end 2018, settlement of these obligations was not expected to require the use of working capital in 2019, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Chevron has an automatic shelf registration statement that expires in May 2021 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

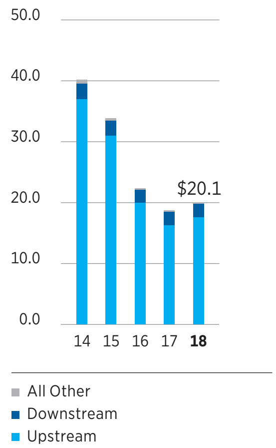
Cash provided by operating activities
Billions of dollars



Total debt at year-end
Billions of dollars

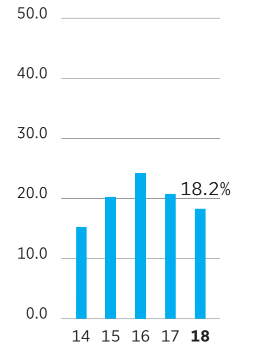


Capital & exploratory expenditures*
Billions of dollars



* Includes equity in affiliates.

Ratio of total debt to total debt-plus-Chevron Corporation stockholders' equity
Percent



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

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

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

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

Capital and Exploratory Expenditures

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

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

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

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

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

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

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

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

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

Financial Ratios

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

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

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

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

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

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

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

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

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 22 beginning on page 81.
2 Does not include amounts related to the company's income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates of the periods in which such liabilities may become payable. The company does not expect settlement of such liabilities to have a material effect on its consolidated financial position or liquidity in any single period.
3 $9.9 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2020–2021 period. The amounts represent only the principal balance.
4 Excludes capital lease obligations.
5 Does not include commodity purchase obligations that are not fixed or determinable. These obligations are generally monetized in a relatively short period of time through sales transactions or similar agreements with third parties. Examples include obligations to purchase LNG, regasified natural gas and refinery products at indexed prices.

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

Direct Guarantees

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

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

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

Financial and Derivative Instrument Market Risk

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 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 2018.

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

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

The company uses the Monte Carlo simulation method as its Value-at-Risk (VaR) model to estimate the maximum potential loss in fair value, at the 95% confidence level with a one-day holding period, from the effect of adverse changes in market conditions on derivative commodity instruments held or issued. Based on these inputs, the VaR for the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2018 and 2017 was not material to the company's cash flows or results of operations.

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

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

Transactions With Related Parties

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

Litigation and Other Contingencies

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

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

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

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

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

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

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

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

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

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

Environmental Matters

The company is subject to various international, federal, state and local environmental, health and safety laws, regulations and market-based programs. These laws, regulations and programs continue to evolve and are expected to increase in both number and complexity over time and govern not only the manner in which the company conducts its operations, but also the products it sells. For example, international agreements and national, regional, and state legislation (e.g., California AB32, SB32 and AB398) and regulatory measures that aim to limit or reduce greenhouse gas (GHG) emissions are currently in various stages of implementation. Consideration of GHG issues and the responses to those issues through international agreements and national, regional or state legislation or regulations are integrated into the company's strategy and planning, capital investment reviews and risk management tools and processes, where applicable. They are also factored into the company's long-range supply, demand and energy price forecasts. These forecasts reflect long-range effects from renewable fuel penetration, energy efficiency standards, climate-related policy actions, and demand response to oil and natural gas prices. In addition, legislation and regulations intended to address hydraulic fracturing also continue to evolve at the national, state and local levels. Refer to "Risk Factors" in Part I, Item 1A, on pages 18 through 21 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 2018 at approximately $2.0 billion for its consolidated companies. Included in these expenditures were approximately $0.5 billion of environmental capital expenditures and $1.5 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

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

Critical Accounting Estimates and Assumptions

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

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

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

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

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

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

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

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

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

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

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

The company routinely performs impairment reviews when triggering events arise to determine whether any write-down in the carrying value of an asset or asset group is required. For example, when significant downward revisions to crude oil and natural gas reserves are made for any single field or concession, an impairment review is performed to determine if the carrying value of the asset remains recoverable. Similarly, a significant downward revision in the company's crude oil or natural gas price outlook would trigger impairment reviews for impacted upstream assets. In addition, impairments could occur due to changes in national, state or local environmental regulations or laws, including those designed to stop or impede the development or production of oil and gas. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets' associated carrying values.

Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for impairment when the fair value of the investment falls below the company's carrying value. When this occurs, a determination must be made as to whether this loss is other-than-temporary, in which case the investment is impaired. Because of the number of differing assumptions potentially affecting whether an investment is impaired in any period or the amount of the impairment, a sensitivity analysis is not practicable.

No individually material impairments of PP&E or Investments were recorded for 2018 or 2017. The company reported impairments for certain oil and gas properties in Brazil and the United States during 2016 due to reservoir performance and lower crude oil prices. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired, or resulted in larger impacts on impaired assets.

Asset Retirement Obligations In the determination of fair value for an asset retirement obligation (ARO), the company uses various assumptions and judgments, including such factors as the existence of a legal obligation, estimated amounts and timing of settlements, discount and inflation rates, and the expected impact of advances in technology and process improvements. A sensitivity analysis of the ARO impact on earnings for 2018 is not practicable, given the broad range of the company's long-lived assets and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions would have reduced estimated future obligations, thereby lowering accretion expense and amortization costs, whereas unfavorable changes would have the opposite effect. Refer to Note 24 on page 88 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 22, beginning on page 81, includes information on the funded status of the company's pension and other postretirement benefit (OPEB) plans reflected on the Consolidated Balance Sheet; the components of pension and OPEB expense reflected on the Consolidated Statement of Income; and the related underlying assumptions.

The determination of pension plan expense and obligations is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. Critical assumptions in determining expense and obligations for OPEB plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, are the discount rate and the assumed health care cost-trend rates. Information related to the company's processes to develop these assumptions is included on page 83 in Note 22 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes beyond the company's control.

For 2018, the company used an expected long-term rate of return of 6.75 percent and a discount rate for service costs of 3.7 percent and a discount rate for interest cost of 3.0 percent for U.S. pension plans. The actual return for 2018 was negative. For the 10 years ended December 31, 2018, actual asset returns averaged 7.9 percent for these plans. Additionally, with the exception of three years within this 10-year period, actual asset returns for these plans equaled or exceeded 6.75 percent during each year.

Total pension expense for 2018 was $1.1 billion. An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in this assumption for the company's primary U.S. pension plan, which accounted for about 63 percent of companywide pension expense, would have reduced total pension plan expense for 2018 by approximately $83 million. A 1 percent increase in the discount rates for this same plan would have reduced pension expense for 2018 by approximately $271 million.

The aggregate funded status recognized at December 31, 2018, was a net liability of approximately $3.9 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At December 31, 2018, the company used a discount rate of 4.2 percent to measure the obligations for the U.S. pension plans. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan, which accounted for about 62 percent of the companywide pension obligation, would have reduced the plan obligation by approximately $339 million, and would have decreased the plan's underfunded status from approximately $1.8 billion to $1.4 billion.

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

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

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

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

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

New Accounting Standards

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

Quarterly Results

Unaudited

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

Beginning in 2018, excises taxes are netted in "Taxes other than on income" in accordance with ASU 2014-09. Refer to Note 25, "Revenue" beginning on page 88.

[2] 2017 adjusted to conform to ASU 2017-07. Refer to Note 4, "New Accounting Standards" beginning on page 60.

Management's Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

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

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

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

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

Management's Report on Internal Control Over Financial Reporting

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

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

Michael K. Wirth 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, 2019

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Chevron Corporation:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chevron Corporation and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2018 including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and, 2017 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. 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, 2019

We have served as the Company's auditor since 1935.

Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2018	2017	2016
Revenues and Other Income			
Sales and other operating revenues[1]	**$ 158,902**	$ 134,674	$ 110,215
Income from equity affiliates	**6,327**	4,438	2,661
Other income	**1,110**	2,610	1,596
Total Revenues and Other Income	**166,339**	141,722	114,472
Costs and Other Deductions			
Purchased crude oil and products	**94,578**	75,765	59,321
Operating expenses[2]	**20,544**	19,127	19,902
Selling, general and administrative expenses[2]	**3,838**	4,110	4,305
Exploration expenses	**1,210**	864	1,033
Depreciation, depletion and amortization	**19,419**	19,349	19,457
Taxes other than on income[1]	**4,867**	12,331	11,668
Interest and debt expense	**748**	307	201
Other components of net periodic benefit costs[2]	**560**	648	745
Total Costs and Other Deductions	**145,764**	132,501	116,632
Income (Loss) Before Income Tax Expense	**20,575**	9,221	(2,160)
Income Tax Expense (Benefit)	**5,715**	(48)	(1,729)
Net Income (Loss)	**14,860**	9,269	(431)
Less: Net income attributable to noncontrolling interests	**36**	74	66
Net Income (Loss) Attributable to Chevron Corporation	**$ 14,824**	$ 9,195	$ (497)
Per Share of Common Stock			
Net Income (Loss) Attributable to Chevron Corporation			
- Basic	**$ 7.81**	$ 4.88	$ (0.27)
- Diluted	**$ 7.74**	$ 4.85	$ (0.27)

[1] 2017 and 2016 include excise, value-added and similar taxes of $7,189 and $6,905, respectively, collected on behalf of third parties. Beginning in 2018, these taxes are netted in "Taxes other than on income" in accordance with Accounting Standards Update (ASU) 2014-09. Refer to Note 25, "Revenue" beginning on page 88.

[2] 2017 and 2016 adjusted to conform to ASU 2017-07. Refer to Note 4, "New Accounting Standards" beginning on page 60.

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2018	2017	2016
Net Income (Loss)	**$ 14,860**	$ 9,269	$ (431)
Currency translation adjustment			
Unrealized net change arising during period	**(19)**	57	(22)
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	**(5)**	(3)	27
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	**792**	817	918
Actuarial gain (loss) arising during period	**85**	(571)	(315)
Prior service credits (cost)			
Amortization to net income of net prior service costs and curtailments	**(13)**	(20)	19
Prior service (costs) credits arising during period	**(26)**	(1)	345
Defined benefit plans sponsored by equity affiliates - benefit (cost)	**23**	19	(19)
Income (taxes) benefit on defined benefit plans	**(230)**	(44)	(505)
Total	**631**	200	443
Other Comprehensive Gain, Net of Tax	**607**	254	448
Comprehensive Income	**15,467**	9,523	17
Comprehensive income attributable to noncontrolling interests	**(36)**	(74)	(66)
Comprehensive Income (Loss) Attributable to Chevron Corporation	**$ 15,431**	$ 9,449	$ (49)

See accompanying Notes to the Consolidated Financial Statements.

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

	At December 31	
	2018	2017
Assets		
Cash and cash equivalents	**$ 9,342**	$ 4,813
Time deposits	**950**	—
Marketable securities	**53**	9
Accounts and notes receivable (less allowance: 2018 - $869; 2017 - $490)	**15,050**	15,353
Inventories:		
Crude oil and petroleum products	**3,383**	3,142
Chemicals	**487**	476
Materials, supplies and other	**1,834**	1,967
Total inventories	**5,704**	5,585
Prepaid expenses and other current assets	**2,922**	2,800
Total Current Assets	**34,021**	28,560
Long-term receivables, net	**1,942**	2,849
Investments and advances	**35,546**	32,497
Properties, plant and equipment, at cost	**340,244**	344,485
Less: Accumulated depreciation, depletion and amortization	**171,037**	166,773
Properties, plant and equipment, net	**169,207**	177,712
Deferred charges and other assets	**6,766**	7,017
Goodwill	**4,518**	4,531
Assets held for sale	**1,863**	640
Total Assets	**$ 253,863**	$ 253,806
Liabilities and Equity		
Short-term debt	**$ 5,726**	$ 5,192
Accounts payable	**13,953**	14,565
Accrued liabilities	**4,927**	5,267
Federal and other taxes on income	**1,628**	1,600
Other taxes payable	**937**	1,113
Total Current Liabilities	**27,171**	27,737
Long-term debt[1]	**28,733**	33,571
Deferred credits and other noncurrent obligations	**19,742**	21,106
Noncurrent deferred income taxes	**15,921**	14,652
Noncurrent employee benefit plans	**6,654**	7,421
Total Liabilities[2]	**$ 98,221**	$ 104,487
Preferred stock (authorized 100,000,000 shares; $1.00 par value; none issued)	**—**	—
Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2018 and 2017)	**1,832**	1,832
Capital in excess of par value	**17,112**	16,848
Retained earnings	**180,987**	174,106
Accumulated other comprehensive losses	**(3,544)**	(3,589)
Deferred compensation and benefit plan trust	**(240)**	(240)
Treasury stock, at cost (2018 - 539,838,890 shares; 2017 - 537,974,695)	**(41,593)**	(40,833)
Total Chevron Corporation Stockholders' Equity	**154,554**	148,124
Noncontrolling interests	**1,088**	1,195
Total Equity	**155,642**	149,319
Total Liabilities and Equity	**$ 253,863**	$ 253,806

1 Includes capital lease obligations of $127 and $94 at December 31, 2018 and 2017, respectively.

2 Refer to Note 23, "Other Contingencies and Commitments" beginning on page 86.

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Millions of dollars

	Year ended December 31		
	2018	2017	2016
Operating Activities			
Net Income (Loss)	**$ 14,860**	$ 9,269	$ (431)
Adjustments			
Depreciation, depletion and amortization	**19,419**	19,349	19,457
Dry hole expense	**687**	198	489
Distributions less than income from equity affiliates[1]	**(3,580)**	(2,380)	(1,549)
Net before-tax gains on asset retirements and sales	**(619)**	(2,195)	(1,149)
Net foreign currency effects	**123**	131	186
Deferred income tax provision	**1,050**	(3,203)	(3,835)
Net decrease (increase) in operating working capital[2]	**(718)**	520	(327)
Decrease (increase) in long-term receivables	**418**	(368)	(131)
Net decrease (increase) in other deferred charges[2]	**—**	(254)	178
Cash contributions to employee pension plans	**(1,035)**	(980)	(870)
Other	**13**	251	672
Net Cash Provided by Operating Activities[1,2]	**30,618**	20,338	12,690
Investing Activities			
Capital expenditures	**(13,792)**	(13,404)	(18,109)
Proceeds and deposits related to asset sales and returns of investment[1,2]	**2,392**	5,096	3,476
Net maturities of (investments in) time deposits	**(950)**	—	—
Net sales (purchases) of marketable securities	**(51)**	4	297
Net repayment (borrowing) of loans by equity affiliates	**111**	(16)	(2,034)
Net Cash Used for Investing Activities[1,2]	**(12,290)**	(8,320)	(16,370)
Financing Activities			
Net borrowings (repayments) of short-term obligations	**2,021**	(5,142)	2,130
Proceeds from issuances of long-term debt	**218**	3,991	6,924
Repayments of long-term debt and other financing obligations	**(6,741)**	(6,310)	(1,584)
Cash dividends - common stock	**(8,502)**	(8,132)	(8,032)
Distributions to noncontrolling interests	**(91)**	(78)	(63)
Net sales (purchases) of treasury shares	**(604)**	1,117	650
Net Cash Provided by (Used for) Financing Activities	**(13,699)**	(14,554)	25
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	**(91)**	65	(53)
Net Change in Cash, Cash Equivalents and Restricted Cash	**4,538**	(2,471)	(3,708)
Cash, Cash Equivalents and Restricted Cash at January 1	**5,943**	8,414	12,122
Cash, Cash Equivalents and Restricted Cash at December 31	**$ 10,481**	$ 5,943	$ 8,414

[1] 2017 and 2016 adjusted to conform to ASU 2016-15. Refer to Note 3, “Information Relating to the Consolidated Statement of Cash Flows” beginning on page 59.
[2] 2017 and 2016 adjusted to conform to ASU 2016-18. Refer to Note 3, “Information Relating to the Consolidated Statement of Cash Flows” beginning on page 59.

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	Common Stock[1]	Retained Earnings	Acc. Other Comprehensive Income (Loss)	Treasury Stock (*at cost*)	Chevron Corp. Stockholders' Equity	Noncontrolling Interests	Total Equity
Balance at December 31, 2015	**$ 17,922**	**$ 181,578**	**$ (4,291)**	**$ (42,493)**	**$ 152,716**	**$ 1,170**	**$153,886**
Treasury stock transactions	265	—	—	—	265	—	265
Net income (loss)	—	(497)	—	—	(497)	66	(431)
Cash dividends	—	(8,032)	—	—	(8,032)	(63)	(8,095)
Stock dividends	—	(3)	—	—	(3)	—	(3)
Other comprehensive income	—	—	448	—	448	—	448
Purchases of treasury shares	—	—	—	(2)	(2)	—	(2)
Issuances of treasury shares	—	—	—	661	661	—	661
Other changes, net	—	—	—	—	—	(7)	(7)
Balance at December 31, 2016	**$ 18,187**	**$ 173,046**	**$ (3,843)**	**$ (41,834)**	**$ 145,556**	**$ 1,166**	**$146,722**
Treasury stock transactions	253	—	—	—	253	—	253
Net income (loss)	—	9,195	—	—	9,195	74	9,269
Cash dividends	—	(8,132)	—	—	(8,132)	(78)	(8,210)
Stock dividends	—	(3)	—	—	(3)	—	(3)
Other comprehensive income	—	—	254	—	254	—	254
Purchases of treasury shares	—	—	—	(1)	(1)	—	(1)
Issuances of treasury shares	—	—	—	1,002	1,002	—	1,002
Other changes, net	—	—	—	—	—	33	33
Balance at December 31, 2017	**$ 18,440**	**$ 174,106**	**$ (3,589)**	**$ (40,833)**	**$ 148,124**	**$ 1,195**	**$149,319**
Treasury stock transactions	264	—	—	—	264	—	264
Net income (loss)	—	14,824	—	—	14,824	36	14,860
Cash dividends	—	(8,502)	—	—	(8,502)	(91)	(8,593)
Stock dividends	—	(3)	—	—	(3)	—	(3)
Other comprehensive income	—	—	607	—	607	—	607
Purchases of treasury shares	—	—	—	(1,751)	(1,751)	—	(1,751)
Issuances of treasury shares	—	—	—	991	991	—	991
Other changes, net[2]	—	562	(562)	—	—	(52)	(52)
Balance at December 31, 2018	**$ 18,704**	**$ 180,987**	**$ (3,544)**	**$ (41,593)**	**$ 154,554**	**$ 1,088**	**$155,642**

	Common Stock Share Activity		
	Issued[3]	**Treasury**	**Outstanding**
Balance at December 31, 2015	**2,442,677**	**(559,863)**	**1,882,814**
Purchases	—	(20)	(20)
Issuances	—	8,713	8,713
Balance at December 31, 2016	**2,442,677**	**(551,170)**	**1,891,507**
Purchases	—	(10)	(10)
Issuances	—	13,205	13,205
Balance at December 31, 2017	**2,442,677**	**(537,975)**	**1,904,702**
Purchases	—	(14,912)	(14,912)
Issuances	—	13,048	13,048
Balance at December 31, 2018	**2,442,677**	**(539,839)**	**1,902,838**

[1] Beginning and ending balances for all periods include capital in excess of par, common stock issued at par for $1,832, and $(240) associated with Chevron's Benefit Plan Trust. Changes reflect capital in excess of par.

[2] In 2018, Chevron reclassified stranded tax effects in "Accumulated other comprehensive losses" to "Retained earnings" in conjunction with the adoption of ASU 2018-02. Refer to Note 2, "Changes in Accumulated Other Comprehensive Loss" on page 58 and Note 4, "New Accounting Standards" on page 60.

[3] Beginning and ending total issued share balances include 14,168 shares associated with Chevron's Benefit Plan Trust.

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 circumstances change and additional information becomes known.

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.

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.

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 and Consolidated Statement of Equity.

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 cost or 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 20, beginning on page 79, 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 8, beginning on page 63, 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 24, on page 88, 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 24, on page 88, 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 The company accounts for each delivery order of crude oil, natural gas, petroleum and chemical products as a separate performance obligation. Revenue is recognized when the performance obligation is satisfied, which typically occurs at the point in time when control of the product transfers to the customer. Payment is generally due within 30 days of delivery. The company accounts for delivery transportation as a fulfillment cost, not a separate performance obligation, and recognizes these costs as an operating expense in the period when revenue for the related commodity is recognized.

Revenue is measured as the amount the company expects to receive in exchange for transferring commodities to the customer. The company's commodity sales are typically based on prevailing market-based prices and may include discounts and allowances. Until market prices become known under terms of the company's contracts, the transaction price included in revenue is based on the company's estimate of the most likely outcome.

Discounts and allowances are estimated using a combination of historical and recent data trends. When deliveries contain multiple products, an observable standalone selling price is generally used to measure revenue for each product. The company includes estimates in the transaction price only to the extent that a significant reversal of revenue is not probable in subsequent periods.

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 net basis in "Taxes other than on income" on the Consolidated Statement of Income, on page 50. 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.

Prior to the adoption of ASC 606 on January 1, 2018, revenues associated with sales of crude oil, natural gas, petroleum and chemicals products, and all other sources were recorded when title passed 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 were 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 were presented on a gross basis 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 ended December 31, 2018, are reflected in the table below.

	Currency Translation Adjustments	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total
Balance at December 31, 2015	**$ (140)**	**$ (29)**	**$ (2)**	**$ (4,120)**	**$ (4,291)**
Components of Other Comprehensive Income (Loss)[1]:					
Before Reclassifications	(22)	27	—	(161)	(156)
Reclassifications[2]	—	—	—	604	604
Net Other Comprehensive Income (Loss)	(22)	27	—	443	448
Balance at December 31, 2016	**$ (162)**	**$ (2)**	**$ (2)**	**$ (3,677)**	**$ (3,843)**
Components of Other Comprehensive Income (Loss)[1]:					
Before Reclassifications	57	(3)	—	(310)	(256)
Reclassifications[2]	—	—	—	510	510
Net Other Comprehensive Income (Loss)	57	(3)	—	200	254
Balance at December 31, 2017	**$ (105)**	**$ (5)**	**$ (2)**	**$ (3,477)**	**$ (3,589)**
Components of Other Comprehensive Income (Loss)[1]:					
Before Reclassifications	(19)	(5)	—	28	4
Reclassifications[2]	—	—	—	603	603
Net Other Comprehensive Income (Loss)	(19)	(5)	—	631	607
Stranded Tax Reclassification to Retained Earnings[3]	—	—	—	(562)	(562)
Balance at December 31, 2018	**$ (124)**	**$ (10)**	**$ (2)**	**$ (3,408)**	**$ (3,544)**

[1] All amounts are net of tax.

[2] Refer to Note 22 beginning on page 81, for reclassified components totaling $779 that are included in employee benefit costs for the year ended December 31, 2018. Related income taxes for the same period, totaling $176, are reflected in Income Tax Expense on the Consolidated Statement of Income. All other reclassified amounts were insignificant.

[3] Stranded tax reclassification to retained earnings per ASU 2018-02. Refer to Note 4, "New Accounting Standards" on page 60.

Note 3
Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2018	2017	2016
Net decrease (increase) in operating working capital was composed of the following:			
Decrease (increase) in accounts and notes receivable	**$ 437**	$ (915)	$ (2,121)
Decrease (increase) in inventories	**(424)**	(267)	603
Decrease (increase) in prepaid expenses and other current assets [1]	**(149)**	173	829
Increase (decrease) in accounts payable and accrued liabilities [1]	**(494)**	998	366
Increase (decrease) in income and other taxes payable	**(88)**	531	(4)
Net decrease (increase) in operating working capital	**$ (718)**	$ 520	$ (327)
Net cash provided by operating activities includes the following cash payments:			
Interest on debt (net of capitalized interest)	**$ 736**	$ 265	$ 158
Income taxes	**4,748**	3,132	1,935
Proceeds and deposits related to asset sales and returns of investment consisted of the following gross amounts:			
Proceeds and deposits related to asset sales [1]	**$ 2,000**	$ 4,930	$ 3,154
Returns of investment from equity affiliates [2]	**392**	166	322
Proceeds and deposits related to asset sales and returns of investment	**$ 2,392**	$ 5,096	$ 3,476
Net maturities (investments) of time deposits consisted of the following gross amounts:			
Investments in time deposits	**$ (950)**	$ —	$ —
Maturities of time deposits	**—**	—	—
Net maturities of (investments in) time deposits	**$ (950)**	$ —	$ —
Net sales (purchases) of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (51)**	$ (3)	$ (9)
Marketable securities sold	**—**	7	306
Net sales (purchases) of marketable securities	**$ (51)**	$ 4	$ 297
Net repayment (borrowing) of loans by equity affiliates:			
Borrowing of loans by equity affiliates	**$ —**	$ (142)	$ (2,341)
Repayment of loans by equity affiliates	**111**	126	307
Net repayment (borrowing) of loans by equity affiliates	**$ 111**	$ (16)	$ (2,034)
Net borrowings (repayments) of short-term obligations consisted of the following gross and net amounts:			
Proceeds from issuances of short-term obligations	**$ 2,486**	$ 5,051	$ 14,778
Repayments of short-term obligations	**(4,136)**	(8,820)	(12,558)
Net borrowings (repayments) of short-term obligations with three months or less maturity	**3,671**	(1,373)	(90)
Net borrowings (repayments) of short-term obligations	**$ 2,021**	$ (5,142)	$ 2,130

[1] 2017 and 2016 adjusted to conform to ASU 2016-18.
[2] Per ASU 2016-15.

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 (purchases) of treasury shares” represents the cost of common shares acquired less the cost of shares issued for share-based compensation plans. Purchases totaled $1,751, $1 and $2 in 2018, 2017 and 2016, respectively. The company purchased 14.9 million shares under its stock repurchase plan for $1,750 in 2018. No shares were repurchased under the plan in 2017 or 2016.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. “Depreciation, depletion and amortization,” “Dry hole expense” and “Deferred income tax provision” collectively include approximately $1.1 billion in non-cash reductions to properties, plant and equipment recorded in 2018 relating to impairments and other non-cash charges.

Refer also to Note 24, on page 88, 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, 2018.

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		
	2018	2017	2016
Additions to properties, plant and equipment *	**$ 13,384**	$ 13,222	$ 17,742
Additions to investments	**65**	25	55
Current-year dry hole expenditures	**344**	157	313
Payments for other liabilities and assets, net	**(1)**	—	(1)
Capital expenditures	**13,792**	13,404	18,109
Expensed exploration expenditures	**523**	666	544
Assets acquired through capital lease obligations and other financing obligations	**75**	8	5
Capital and exploratory expenditures, excluding equity affiliates	**14,390**	14,078	18,658
Company's share of expenditures by equity affiliates	**5,716**	4,743	3,770
Capital and exploratory expenditures, including equity affiliates	**$ 20,106**	$ 18,821	$ 22,428

* Excludes non-cash additions of $25 in 2018, $1,183 in 2017 and $56 in 2016.

On January 1, 2018, Chevron adopted Accounting Standards Updates (ASU) 2016-15 and 2016-18, which require retrospective adjustment of prior periods in the Statement of Cash Flows.

In addition to other requirements, ASU 2016-15 specifies new standards for the classification of distributions from equity affiliates. In adopting these new standards, Chevron utilized the cumulative earnings approach to evaluate returns on and returns of investment from equity affiliates. For the year ended 2017 and 2016, a total of $166 and $322, respectively, was reclassified from "Distributions less than income from equity affiliates" to "Proceeds and deposits related to asset sales and returns of investment."

Adoption of ASU 2016-18 requires the inclusion of restricted cash and associated changes in restricted cash in the Consolidated Statement of Cash Flows. The impact of ASU 2016-18 is captured across several line items in the Statement of Cash Flows, including "Net decrease (increase) in operating working capital," "Decrease (increase) in other deferred charges," and "Proceeds and deposits related to asset sales and returns of investment" with associated net changes captured in both "Net Cash Provided by Operating Activities" and "Net Cash Used for Investing Activities." The line item "Net sales (purchases) of other short-term investments" was removed in conjunction with the adoption of ASU 2016-18.

The table below quantifies the beginning and ending balances of restricted cash and restricted cash equivalents in the Consolidated Balance Sheet:

	Year ended December 31			
	2018	2017	2016	2015
Cash and cash equivalents	**$ 9,342**	$ 4,813	$ 6,988	$ 11,022
Restricted cash included in "Prepaid expenses and other current assets"	**341**	405	488	196
Restricted cash included in "Deferred charges and other assets"	**798**	725	938	904
Total cash, cash equivalents and restricted cash	**$ 10,481**	$ 5,943	$ 8,414	$ 12,122

Note 4
New Accounting Standards

Revenue Recognition (Topic 606): Revenue from Contracts with Customers On January 1, 2018, Chevron adopted ASU 2014-09 and its related amendments using the modified retrospective transition method, which did not require the restatement of prior periods. The impact of the adoption of the standard did not have a material effect on the company's consolidated financial statements. For additional information on the company's revenue, refer to Note 25 beginning on page 88.

Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20) On January 1, 2018, the company adopted ASU 2017-05, which provides clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. The adoption of the standard had no impact on the company's consolidated financial statements.

Compensation—Retirement Benefits (Topic 715) Effective January 1, 2018, Chevron adopted ASU 2017-07 on a retrospective basis. 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 effects of retrospective adoption on the Consolidated Statement of Income for 2017 and 2016 were to move $310 and $366 from "Operating expenses" and $338 and $379 from "Selling, general and administrative expenses" to "Other components of net periodic benefits cost," respectively.

Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments Effective January 1, 2018, Chevron adopted ASU 2016-15 on a retrospective basis. The standard provides clarification on how certain cash receipts and cash payments are presented and classified on the Consolidated Statement of Cash Flows. The adoption of this ASU did not have a material impact on the company's Consolidated Statement of Cash Flows. For additional information, refer to Note 3 beginning on page 59.

Statement of Cash Flows (Topic 230) Restricted Cash Effective January 1, 2018, Chevron adopted ASU 2016-18 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 Consolidated Statement of Cash Flows and to provide a reconciliation to the Consolidated 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 Consolidated Balance Sheet. The company's restricted cash balances are now included in the beginning and ending balances on the Consolidated Statement of Cash Flows. For additional information, refer to Note 3 beginning on page 59.

Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In fourth quarter 2018, the company elected to early adopt ASU 2018-02, which permits the reclassification of stranded tax effects in accumulated other comprehensive income as a result of U.S. tax reform. Accordingly, Chevron reclassified $562 from "Accumulated other comprehensive losses" to "Retained earnings" associated with the reduction of the U.S. statutory tax rate from 35 percent to 21 percent. In accordance with its accounting policy, the company releases stranded income tax effects from accumulated other comprehensive income in the period the underlying activity ceases to exist. ASU 2018-02 allowed for the reclassification of stranded tax effects as a result of the change in tax rates due to U.S. tax reform to be recorded upon adoption of the ASU, rather than at the actual date that the underlying activity ceases to exist. For additional detail, refer to Note 2 beginning on page 58.

Leases (Topic 842) In February 2016, the Financial Accounting Standards Board (FASB) issued ASU 2016-02, which became effective for the company January 1, 2019. The standard requires that lessees present right-of-use assets and lease liabilities on the Consolidated Balance Sheet. The company plans to elect the short-term lease exception provided for in the standard and therefore will only recognize right-of-use assets and lease liabilities for leases with a term greater than one year. The company further intends to elect the option to apply the transition provisions of the new standard at the adoption date instead of the earliest comparative period presented in the financial statements. The company plans to elect the package of practical expedients to not re-evaluate existing lease contracts or lease classifications and therefore will not make changes to those leases already recognized on the Consolidated Balance Sheet under ASC 840 until the leases are fully amortized, amended, or modified. In addition, the company will not reassess initial direct costs for any existing leases. The company intends to apply the land easement practical expedient. Chevron plans to elect the practical expedient to not separate non-lease components from lease components for most asset classes except for certain asset classes that have significant non-lease (i.e., service) components in addition to the lease component. The company will reclassify some contracts, currently not classified as leases, as operating leases under the new standard.

The company completed accounting policy and disclosure updates and system implementation necessary to meet the standard's requirements. The company does not expect the adoption of the ASU to have a material impact on finance leases, which are currently referred to as capital leases. The company estimates that the operating lease right-of-use assets and lease liabilities on the Consolidated Balance Sheet are approximately $4 billion, as of January 1, 2019. The company expects the implementation of the standard will have a minimal impact on the Consolidated Statement of Income and Consolidated Statement of Cash Flows.

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.

Note 5
Lease Commitments

Certain noncancelable 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, vessels, 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 below:

	At December 31	
	2018	2017
Upstream	**$ 719**	$ 678
Downstream	**99**	99
All Other	**—**	—
Total	**818**	777
Less: Accumulated amortization	**617**	515
Net capitalized leased assets	**$ 201**	$ 262

Rental expenses incurred for operating leases during 2018, 2017 and 2016 were as follows:

	Year ended December 31		
	2018	2017	2016
Minimum rentals	**$ 820**	$ 726	$ 943
Contingent rentals	**1**	1	2
Total	**821**	727	945
Less: Sublease rental income	**5**	6	7
Net rental expense	**$ 816**	$ 721	$ 938

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, 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, 2018, 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:

	At December 31	
	Operating Leases	Capital Leases *
Year 2019	$ 540	$ 30
2020	492	22
2021	378	17
2022	242	16
2023	166	16
Thereafter	341	132
Total	$ 2,159	$ 233
Less: Amounts representing interest and executory costs		$ (88)
Net present values		145
Less: Capital lease obligations included in short-term debt		(18)
Long-term capital lease obligations		$ 127

* Excluded from the table is an executed but not-yet-commenced capital lease with payments of $14, $15, $22, $21, $21, and $219 for 2019, 2020, 2021, 2022, 2023, and thereafter, respectively.

Note 6

Summarized Financial Data – Chevron U.S.A. Inc.

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of Chevron Corporation. CUSA and its subsidiaries manage and operate most of Chevron's U.S. businesses. Assets include those related to the exploration and production of crude oil, natural gas and natural gas liquids and those associated with the refining, marketing, supply and distribution of products derived from petroleum, excluding most of the regulated pipeline operations of Chevron. CUSA also holds the company's investment in the Chevron Phillips Chemical Company LLC joint venture, which is accounted for using the equity method. The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2018	2017	2016
Sales and other operating revenues	**$ 125,076**	$ 104,054	$ 83,715
Total costs and other deductions	**121,351**	103,904	87,429
Net income (loss) attributable to CUSA	**4,334**	4,842	(1,177)

	At December 31	
	2018	2017
Current assets	**$ 12,819**	$ 12,163
Other assets	**55,814**	54,994
Current liabilities	**16,376**	17,379
Other liabilities	**12,906**	12,541
Total CUSA net equity	**$ 39,351**	$ 37,237
Memo: Total debt	**$ 3,049**	$ 3,056

Note 7

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 14, beginning on page 69, for a discussion of TCO operations. Summarized financial information for 100 percent of TCO is presented in the table below:

	Year ended December 31		
	2018	2017	2016
Sales and other operating revenues	**$ 17,260**	$ 13,363	$ 10,460
Costs and other deductions	**7,446**	6,507	6,822
Net income attributable to TCO	**6,908**	4,841	2,563

	At December 31	
	2018	2017
Current assets	**$ 2,374**	$ 4,239
Other assets	**34,727**	26,411
Current liabilities	**3,069**	2,517
Other liabilities	**6,357**	6,266
Total TCO net equity	**$ 27,675**	$ 21,867

Note 8

Fair Value Measurements

The tables 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, 2018, and December 31, 2017.

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, 2018.

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 2018 or 2017.

Investments and Advances The company did not have any individually material impairments of investments and advances in 2018 or 2017.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2018				At December 31, 2017			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	$ 53	$ 53	$ —	$ —	$ 9	$ 9	$ —	$ —
Derivatives	283	185	98	—	22	—	22	—
Total assets at fair value	$ 336	$ 238	$ 98	$ —	$ 31	$ 9	$ 22	$ —
Derivatives	12	—	12	—	124	78	46	—
Total liabilities at fair value	$ 12	$ —	$ 12	$ —	$ 124	$ 78	$ 46	$ —

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 2018	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2017
Properties, plant and equipment, net (held and used)	$ 102	$ —	$ 62	$ 40	$ 97	$ 603	$ —	$ —	$ 603	$ 658
Properties, plant and equipment, net (held for sale)	1,694	—	1,273	421	638	1,378	—	1,378	—	363
Investments and advances	81	—	20	61	69	28	—	1	27	26
Total nonrecurring assets at fair value	$ 1,877	$ —	$ 1,355	$ 522	$ 804	$ 2,009	$ —	$ 1,379	$ 630	$ 1,047

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 $9,342 and $4,813 at December 31, 2018, and December 31, 2017, respectively. The instruments held in "Time deposits" are bank time deposits with maturities greater than 90 days and had carrying/fair values of $950 and zero at December 31, 2018, and December 31, 2017, respectively. The fair values of cash, cash equivalents and bank time deposits are classified as Level 1 and reflect the cash that would have been received if the instruments were settled at December 31, 2018.

"Cash and cash equivalents" do not include investments with a carrying/fair value of $1,139 and $1,130 at December 31, 2018, and December 31, 2017, respectively. At December 31, 2018, these investments are classified as Level 1 and include restricted funds related to certain upstream abandonment activities, tax payments and a financing program, which are reported in "Deferred charges and other assets" on the Consolidated Balance Sheet. Long-term debt, excluding capital lease obligations, of $18,706 and $23,477 at December 31, 2018, and December 31, 2017, respectively, had estimated fair values of $18,729 and $23,943, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is $17,858 and classified as Level 1. The fair value of other long-term debt is $871 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, 2018 and 2017, were not material.

Note 9
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, 2018, December 31, 2017, and December 31, 2016, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are below:

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

		At December 31	
Type of Contract	Balance Sheet Classification	**2018**	2017
Commodity	Accounts and notes receivable, net	**$ 279**	$ 22
Commodity	Long-term receivables, net	**4**	—
Total assets at fair value		**$ 283**	$ 22
Commodity	Accounts payable	**$ 12**	$ 122
Commodity	Deferred credits and other noncurrent obligations	**—**	2
Total liabilities at fair value		**$ 12**	$ 124

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 **2018**	2017	2016
Commodity	Sales and other operating revenues	**$ 135**	$ (105)	$ (269)
Commodity	Purchased crude oil and products	**(33)**	(9)	(31)
Commodity	Other income	**3**	(2)	—
		$ 105	$ (116)	$ (300)

The table below represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2018 and December 31, 2017.

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

At December 31, 2018	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset	Net Amounts
Derivative Assets	$ 3,685	$ 3,402	$ 283	$ —	$ 283
Derivative Liabilities	$ 3,414	$ 3,402	$ 12	$ —	$ 12
At December 31, 2017					
Derivative Assets	$ 1,169	$ 1,147	$ 22	$ —	$ 22
Derivative Liabilities	$ 1,271	$ 1,147	$ 124	$ —	$ 124

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, time deposits, 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 10
Assets Held for Sale

At December 31, 2018, the company classified $1,863 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. These assets are primarily associated with upstream operations that are anticipated to be sold in the next 12 months. The revenues and earnings contributions of these assets in 2018 were not material.

Note 11
Equity

Retained earnings at December 31, 2018 and 2017, included approximately $22,362 and $18,473, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2018, about 78 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, 748,211 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 12
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 21, "Stock Options and Other Share-Based Compensation," beginning on page 80). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2018	2017	2016
Basic EPS Calculation			
Earnings available to common stockholders - Basic[1]	**$ 14,824**	$ 9,195	$ (497)
Weighted-average number of common shares outstanding[2]	**1,897**	1,882	1,872
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,898**	1,883	1,873
Earnings per share of common stock - Basic	**$ 7.81**	$ 4.88	$ (0.27)
Diluted EPS Calculation			
Earnings available to common stockholders - Diluted[1]	**$ 14,824**	$ 9,195	$ (497)
Weighted-average number of common shares outstanding[2]	**1,897**	1,882	1,872
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**16**	15	—
Total weighted-average number of common shares outstanding	**1,914**	1,898	1,873
Earnings per share of common stock - Diluted	**$ 7.74**	$ 4.85	$ (0.27)

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 13
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 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		
	2018	2017	2016
Upstream			
United States	**$ 3,278**	$ 3,640	$ (2,054)
International	**10,038**	4,510	(483)
Total Upstream	**13,316**	8,150	(2,537)
Downstream			
United States	**2,103**	2,938	1,307
International	**1,695**	2,276	2,128
Total Downstream	**3,798**	5,214	3,435
Total Segment Earnings	**17,114**	13,364	898
All Other			
Interest expense	**(713)**	(264)	(168)
Interest income	**137**	60	58
Other	**(1,714)**	(3,965)	(1,285)
Net Income (Loss) Attributable to Chevron Corporation	**$ 14,824**	$ 9,195	$ (497)

Segment Assets Segment assets do not include intercompany investments or receivables. Assets at year-end 2018 and 2017 are as follows:

	At December 31	
	2018	2017
Upstream		
United States	**$ 42,594**	$ 40,770
International	**153,861**	159,612
Goodwill	**4,518**	4,531
Total Upstream	**200,973**	204,913
Downstream		
United States	**23,866**	23,202
International	**15,622**	17,434
Total Downstream	**39,488**	40,636
Total Segment Assets	**240,461**	245,549
All Other		
United States	**5,100**	4,938
International	**8,302**	3,319
Total All Other	**13,402**	8,257
Total Assets – United States	**71,560**	68,910
Total Assets – International	**177,785**	180,365
Goodwill	**4,518**	4,531
Total Assets	**$ 253,863**	$ 253,806

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2018, 2017 and 2016, 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.

	Year ended December 31[1]		
	2018	2017	2016
Upstream			
United States	**$ 8,926**	$ 3,901	$ 3,148
Intersegment	**13,965**	9,341	7,217
Total United States	**22,891**	13,242	10,365
International	**24,143**	17,209	13,262
Intersegment	**13,679**	11,471	9,518
Total International	**37,822**	28,680	22,780
Total Upstream	**60,713**	41,922	33,145
Downstream			
United States	**56,634**	48,728	40,366
Excise and similar taxes[2]	**—**	4,398	4,335
Intersegment	**2,742**	14	16
Total United States	**59,376**	53,140	44,717
International	**68,963**	57,438	46,388
Excise and similar taxes[2]	**—**	2,791	2,570
Intersegment	**1,132**	1,166	1,068
Total International	**70,095**	61,395	50,026
Total Downstream	**129,471**	114,535	94,743
All Other			
United States	**236**	208	145
Intersegment	**786**	814	960
Total United States	**1,022**	1,022	1,105
International	**—**	1	1
Intersegment	**22**	25	36
Total International	**22**	26	37
Total All Other	**1,044**	1,048	1,142
Segment Sales and Other Operating Revenues			
United States	**83,289**	67,404	56,187
International	**107,939**	90,101	72,843
Total Segment Sales and Other Operating Revenues	**191,228**	157,505	129,030
Elimination of intersegment sales	**(32,326)**	(22,831)	(18,815)
Total Sales and Other Operating Revenues	**$ 158,902**	$ 134,674	$ 110,215

1 Other than the United States, no other country accounted for 10 percent or more of the company's Sales and Other Operating Revenues.
2 Netted in "Taxes other than on income" beginning in 2018 in accordance with ASU 2014-09. Refer to Note 25 beginning on page 88.

Segment Income Taxes Segment income tax expense for the years 2018, 2017 and 2016 is as follows:

	Year ended December 31		
	2018	2017	2016
Upstream			
United States	**$ 811**	$ (3,538)	$ (1,172)
International	**4,687**	2,249	166
Total Upstream	**5,498**	(1,289)	(1,006)
Downstream			
United States	**534**	(419)	503
International	**328**	650	484
Total Downstream	**862**	231	987
All Other	**(645)**	1,010	(1,710)
Total Income Tax Expense (Benefit)	**$ 5,715**	$ (48)	$ (1,729)

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 14, on page 69. Information related to properties, plant and equipment by segment is contained in Note 17, on page 77.

Note 14
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		
	2018	2017	**2018**	2017	2016
Upstream					
Tengizchevroil	**$ 16,017**	$ 13,121	**$ 3,614**	$ 2,581	$ 1,380
Petropiar	**1,361**	1,152	**317**	175	326
Petroboscan	**1,315**	1,080	**357**	154	(133)
Caspian Pipeline Consortium	**1,022**	1,151	**170**	155	145
Angola LNG Limited	**2,496**	2,625	**172**	27	(282)
Other	**1,541**	1,714	**19**	104	(193)
Total Upstream	**23,752**	20,843	**4,649**	3,196	1,243
Downstream					
Chevron Phillips Chemical Company LLC	**6,218**	6,200	**1,034**	723	840
GS Caltex Corporation	**3,924**	3,826	**373**	290	373
Other	**1,383**	1,251	**273**	230	209
Total Downstream	**11,525**	11,277	**1,680**	1,243	1,422
All Other					
Other	**(16)**	(15)	**(2)**	(1)	(4)
Total equity method	**35,261**	$ 32,105	**$ 6,327**	$ 4,438	$ 2,661
Other non-equity method investments	**285**	392			
Total investments and advances	**$ 35,546**	$ 32,497			
Total United States	**$ 7,500**	$ 7,582	**$ 1,033**	$ 788	$ 802
Total International	**$ 28,046**	$ 24,915	**$ 5,294**	$ 3,650	$ 1,859

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, 2018, the company's carrying value of its investment in TCO was about $120 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 7, on page 63, 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 heavy oil Huyapari Field and upgrading project in Venezuela's Orinoco Belt. At December 31, 2018, the company's carrying value of its investment in Petropiar was approximately $136 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.

Petroboscan Chevron has a 39.2 percent interest in Petroboscan, a joint stock company which operates the Boscan Field in Venezuela. At December 31, 2018, the company's carrying value of its investment in Petroboscan was approximately $97 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 $626 at year-end 2018.

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 $1,022, which includes long-term loans of $468 at year-end 2018. 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.

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.

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

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.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $10,378, $8,165 and $5,786 with affiliated companies for 2018, 2017 and 2016, respectively. "Purchased crude oil and products" includes $6,598, $4,800 and $3,468 with affiliated companies for 2018, 2017 and 2016, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $884 and $1,141 due from affiliated companies at December 31, 2018 and 2017, respectively. "Accounts payable" includes $631 and $498 due to affiliated companies at December 31, 2018 and 2017, 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 $3,402, $3,853 and $3,535 at December 31, 2018, 2017 and 2016, respectively.

	Affiliates			Chevron Share		
Year ended December 31	**2018**	2017	2016	**2018**	2017	2016
Total revenues	**$ 84,469**	$ 70,744	$ 59,253	**$ 40,679**	$ 33,460	$ 27,787
Income before income tax expense	**16,693**	13,487	6,587	**6,755**	5,712	3,670
Net income attributable to affiliates	**13,321**	10,751	5,127	**6,384**	4,468	2,876
At December 31						
Current assets	**$ 32,657**	$ 33,883	$ 33,406	**$ 12,813**	$ 13,568	$ 13,743
Noncurrent assets	**87,614**	82,261	75,258	**36,369**	32,643	28,854
Current liabilities	**26,006**	26,873	24,793	**9,843**	10,201	8,996
Noncurrent liabilities	**20,000**	21,447	22,671	**4,446**	4,224	4,255
Total affiliates' net equity	**$ 74,265**	$ 67,824	$ 61,200	**$ 34,893**	$ 31,786	$ 29,346

Note 15
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 seven 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 ("the provincial court"), 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 On February 14, 2011, the provincial court rendered a judgment against Chevron. 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 provincial 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 (the National Court). 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 to hear the appeal. On March 29, 2012, the matter was transferred from the provincial court to the National Court, and on November 22, 2012, the National Court agreed to hear Chevron's cassation appeal. On August 3, 2012, the provincial court 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. On July 10, 2018, Ecuador's Constitutional Court released a decision rejecting Chevron's appeal, which sought to nullify the National Court's judgment against Chevron. No further appeals are available in Ecuador.

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 Appeal 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. 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 May 24, 2018, the Court of Appeal for Ontario upheld the Superior Court's dismissal of Chevron Canada Limited from the case. On June 22, 2018, the Lago Agrio plaintiffs filed leave to appeal the decision of the Court of Appeal for Ontario to the Supreme Court of Canada.

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. 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 June 15, 2018, this decision became a final judgment in Brazil.

On October 15, 2012, the provincial court 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, 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. On July 3, 2018, the Federal Civil Court of Appeals affirmed the National Court, First Instance's, dismissal of the Lago Agrio plaintiffs' recognition and enforcement action based on jurisdictional grounds. On October 5, 2018, the Federal Civil Court of Appeals granted, in part, the admissibility of the Lago Agrio plaintiffs' appeal to the Supreme Court of Argentina.

Chevron continues to believe the Ecuadorian 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 any enforcement action. Chevron expects to continue a vigorous defense of any imposition of liability 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 outside of 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 outside of 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.

On August 30, 2018, the Tribunal issued its Phase Two award in favor of Chevron and Texpet. The Tribunal unanimously held that the Ecuadorian judgment was procured through fraud, bribery and corruption and was based on claims that the Republic of Ecuador had settled and released in the mid-1990s, concluding that the Ecuadorian judgment "violates international public policy" and "should not be recognized or enforced by the courts of other States." Specifically, the Tribunal found that (i) the Republic of Ecuador breached its obligations under the 1995 and 1998 settlement agreements releasing Texpet and its affiliates from public environmental claims (the same claims on which the Ecuadorian judgment was exclusively based) and (ii) the Republic of Ecuador committed a denial of justice under customary international law and under the fair and equitable treatment provision of the BIT due to the fraud and corruption in the Lago Agrio litigation. The Tribunal also found that Texpet satisfied its environmental remediation obligations with a $40 remediation program and that Ecuador certified that Texpet had performed all of its obligations under its settlement agreement. Among other things, the Tribunal ordered the Republic of Ecuador to: (a) take immediate steps to remove the status of enforceability from the Ecuadorian judgment; (b) promptly advise in writing any State where the Lago Agrio plaintiffs may be seeking the enforcement or recognition of the Ecuadorian judgment of the Tribunal's declarations, orders and awards; (c) take measures to "wipe out all the consequences" of Ecuador's "internationally wrongful acts in regard to the Ecuadorian judgment;" and (d) compensate Chevron for any injuries resulting from the Ecuadorian judgment. On December 10, 2018, the Republic of Ecuador filed in the District Court of The Hague a request to set aside the Tribunal's Phase Two Award. The Tribunal has not set a date for Phase Three, the third and final phase of the arbitration, at which damages for Chevron's injuries will be determined.

Company's RICO Action 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, 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. 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, management does not believe the judgment has 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 16
Taxes

Income Taxes		Year ended December 31	
	2018	2017	2016
Income tax expense (benefit)			
U.S. federal			
Current	**$ (181)**	$ (382)	$ (623)
Deferred	**738**	(2,561)	(1,558)
State and local			
Current	**183**	(97)	(15)
Deferred	**(16)**	66	(121)
Total United States	**724**	(2,974)	(2,317)
International			
Current	**4,662**	3,634	2,744
Deferred	**329**	(708)	(2,156)
Total International	**4,991**	2,926	588
Total income tax expense (benefit)	**$ 5,715**	$ (48)	$ (1,729)

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:

	2018	2017	2016
Income (loss) before income taxes			
United States	**$ 4,730**	$ (441)	$ (4,317)
International	**15,845**	9,662	2,157
Total income (loss) before income taxes	**20,575**	9,221	(2,160)
Theoretical tax (at U.S. statutory rate of 21% - 2018, 35% - 2017 & 2016)	**4,321**	3,227	(756)
Effect of U.S. tax reform	**(26)**	(2,020)	—
Equity affiliate accounting effect	**(1,526)**	(1,373)	(704)
Effect of income taxes from international operations*	**3,132**	(130)	608
State and local taxes on income, net of U.S. federal income tax benefit	**162**	39	(44)
Prior year tax adjustments, claims and settlements	**(51)**	(39)	(349)
Tax credits	**(163)**	(199)	(188)
Other U.S.*	**(134)**	447	(296)
Total income tax expense (benefit)	**$ 5,715**	$ (48)	$ (1,729)
Effective income tax rate	**27.8%**	(0.5)%	80.0%

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

The 2018 increase in income tax charge of $5,763, from a benefit of $48 in 2017 to a charge of $5,715 in 2018, is a result of the year-over-year increase in total income before income tax expense, which is primarily due to higher crude oil realizations offset by lower gains on asset sales in 2018 compared to 2017. U.S. tax reform resulted in a benefit of $2,020 being recognized in 2017 reflecting the remeasurement of U.S. deferred tax assets and liabilities. The company's effective tax rate changed from (0.5) percent in 2017 to 28 percent in 2018. The change in effective tax rate is 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 impact of U.S. tax reform to both the 2018 and 2017 results.

As noted above, U.S. tax reform resulted in the remeasurement of U.S. deferred tax assets and liabilities in 2017. The U.S. tax return for 2017 was prepared and filed in 2018 and did not result in any material change to the the provisional amounts that were recognized in 2017, and the amounts are now considered final.

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

	At December 31	
	2018	2017
Deferred tax liabilities		
Properties, plant and equipment	**$ 20,159**	$ 19,869
Investments and other	**4,943**	4,796
Total deferred tax liabilities	**25,102**	24,665
Deferred tax assets		
Foreign tax credits	**(10,536)**	(11,872)
Asset retirement obligations/environmental reserves	**(5,328)**	(5,511)
Employee benefits	**(2,787)**	(3,129)
Deferred credits	**(1,373)**	(1,769)
Tax loss carryforwards	**(4,948)**	(5,463)
Other accrued liabilities	**(595)**	(842)
Inventory	**(505)**	(336)
Miscellaneous	**(3,481)**	(2,415)
Total deferred tax assets	**(29,553)**	(31,337)
Deferred tax assets valuation allowance	**15,973**	16,574
Total deferred taxes, net	**$ 11,522**	$ 9,902

Deferred tax liabilities at the end of 2018 increased by approximately $400 from year-end 2017. The increase was primarily related to property, plant and equipment temporary differences.

Deferred tax assets decreased by approximately $1,800 in 2018. The decrease primarily related to lower foreign tax credits and the utilization of tax loss carryforwards.

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 2018, the company had tax loss carryforwards of approximately $13,731 and tax credit carryforwards of approximately $1,198, 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 2019 through 2036. U.S. foreign tax credit carryforwards of $10,536 will expire between 2019 and 2028.

At December 31, 2018 and 2017, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2018	2017
Deferred charges and other assets	**$ (4,399)**	$ (4,750)
Noncurrent deferred income taxes	**15,921**	14,652
Total deferred income taxes, net	**$ 11,522**	$ 9,902

Enactment of U.S. tax reform in 2017 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 $59,900 at December 31, 2018. 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, 2018, 2017 and 2016. 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.

	2018	2017	2016
Balance at January 1	**$ 4,828**	$ 3,031	$ 3,042
Foreign currency effects	**(6)**	43	1
Additions based on tax positions taken in current year	**239**	1,853	245
Additions for tax positions taken in prior years	**153**	1,166	181
Reductions for tax positions taken in prior years	**(131)**	(90)	(390)
Settlements with taxing authorities in current year	**(13)**	(1,173)	(36)
Reductions as a result of a lapse of the applicable statute of limitations	**—**	(2)	(12)
Balance at December 31	**$ 5,070**	$ 4,828	$ 3,031

Approximately 82 percent of the $5,070 of unrecognized tax benefits at December 31, 2018, 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, 2018. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2013, Nigeria – 2000, Australia – 2006 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 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, 2018, accruals of $33 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $178 as of year-end 2017. Income tax expense (benefit) associated with interest and penalties was $8, $(161) and $38 in 2018, 2017 and 2016, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2018	2017	2016
United States			
Excise and similar taxes on products and merchandise*	**$ 4,830**	$ 4,398	$ 4,335
Consumer excise taxes collected on behalf of third parties*	**(4,830)**	—	—
Import duties and other levies	**15**	11	9
Property and other miscellaneous taxes	**1,577**	1,824	1,680
Payroll taxes	**246**	241	252
Taxes on production	**325**	206	159
Total United States	**2,163**	6,680	6,435
International			
Excise and similar taxes on products and merchandise*	**3,031**	2,791	2,570
Consumer excise taxes collected on behalf of third parties*	**(3,031)**	—	—
Import duties and other levies	**37**	45	33
Property and other miscellaneous taxes	**2,370**	2,563	2,379
Payroll taxes	**132**	137	145
Taxes on production	**165**	115	106
Total International	**2,704**	5,651	5,233
Total taxes other than on income	**$ 4,867**	$ 12,331	$ 11,668

* Beginning in 2018, these taxes are netted in "Taxes other than on income" in accordance with ASU 2014-09. Refer to Note 25, "Revenue" beginning on page 88.

Note 17
Properties, Plant and Equipment[1]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expense[3]		
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Upstream												
United States	**$ 88,155**	$ 84,602	$ 83,929	**$ 39,526**	$ 38,722	$ 39,710	**$ 6,434**	$ 4,995	$ 4,432	**$ 5,328**	$ 5,527	$ 6,576
International	**215,329**	224,211	214,557	**113,603**	123,191	125,502	**4,865**	7,934	12,084	**12,726**	12,096	11,247
Total Upstream	**303,484**	308,813	298,486	**153,129**	161,913	165,212	**11,299**	12,929	16,516	**18,054**	17,623	17,823
Downstream												
United States	**24,685**	23,598	22,795	**10,838**	10,346	10,196	**1,259**	907	528	**751**	753	956
International	**7,237**	7,094	9,350	**3,023**	3,074	4,094	**278**	306	375	**282**	282	332
Total Downstream	**31,922**	30,692	32,145	**13,861**	13,420	14,290	**1,537**	1,213	903	**1,033**	1,035	1,288
All Other												
United States	**4,667**	4,798	5,263	**2,186**	2,341	2,635	**224**	218	198	**320**	677	328
International	**171**	182	183	**31**	38	49	**6**	4	6	**12**	14	18
Total All Other	**4,838**	4,980	5,446	**2,217**	2,379	2,684	**230**	222	204	**332**	691	346
Total United States	**117,507**	112,998	111,987	**52,550**	51,409	52,541	**7,917**	6,120	5,158	**6,399**	6,957	7,860
Total International	**222,737**	231,487	224,090	**116,657**	126,303	129,645	**5,149**	8,244	12,465	**13,020**	12,392	11,597
Total	**$ 340,244**	$344,485	$336,077	**$ 169,207**	$177,712	$182,186	**$13,066**	$14,364	$17,623	**$ 19,419**	$ 19,349	$ 19,457

1 Other than the United States and Australia, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2018. Australia had PP&E of $53,768, $55,514 and $53,962 in 2018, 2017 and 2016, respectively.
2 Net of dry hole expense related to prior years' expenditures of $343, $42 and $175 in 2018, 2017 and 2016, respectively.
3 Depreciation expense includes accretion expense of $654, $668 and $749 in 2018, 2017 and 2016, respectively, and impairments of $735, $1,021 and $3,186 in 2018, 2017 and 2016, respectively.

Note 18
Short-Term Debt

	At December 31	
	2018	2017
Commercial paper[1]	**$ 7,503**	$ 5,379
Notes payable to banks and others with originating terms of one year or less	**28**	—
Current maturities of long-term debt[2]	**4,999**	6,720
Current maturities of long-term capital leases	**18**	15
Redeemable long-term obligations		
Long-term debt	**3,078**	3,078
Capital leases	**—**	—
Subtotal	**15,626**	15,192
Reclassified to long-term debt	**(9,900)**	(10,000)
Total short-term debt	**$ 5,726**	$ 5,192

1 Weighted-average interest rates at December 31, 2018 and 2017, were 2.43 percent and 1.30 percent, respectively.
2 Net of unamortized discounts and issuance costs: $1 in 2018 and $2 in 2017.

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, 2018, the company had no interest rate swaps on short-term debt.

At December 31, 2018, the company had $9,900 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 $325 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, 2018.

The company classified $9,900 and $10,000 of short-term debt as long-term at December 31, 2018 and 2017, 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 19

Long-Term Debt

Total long-term debt including capital lease obligations at December 31, 2018, was $28,733. The company's long-term debt outstanding at year-end 2018 and 2017 was as follows:

	At December 31	
	2018	2017
	Principal	Principal
3.191% notes due 2023	**$ 2,250**	$ 2,250
2.954% notes due 2026	**2,250**	2,250
2.355% notes due 2022	**2,000**	2,000
1.961% notes due 2020	**1,750**	1,750
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
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**	1,000
Floating rate notes due 2019 (2.905%)[1]	**850**	850
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**	700
2.411% notes due 2022	**700**	700
Floating rate notes due 2021 (3.313%)[1]	**650**	650
Floating rate notes due 2022 (3.245%)[1]	**650**	650
1.991% notes due 2020	**600**	600
1.686% notes due 2019	**550**	550
Floating rate notes due 2020 (2.948%)[2]	**400**	400
3.400% loan[3]	**218**	—
8.625% debentures due 2032	**147**	147
8.625% debentures due 2031	**108**	108
8.000% debentures due 2032	**75**	75
9.750% debentures due 2020	**54**	54
8.875% debentures due 2021	**40**	40
Medium-term notes, maturing from 2021 to 2038 (6.629%)[1]	**38**	38
1.718% notes due 2018	**—**	2,000
1.365% notes due 2018	**—**	1,750
Floating rate notes due 2018	**—**	1,650
1.790% notes due 2018	**—**	1,250
Amortizing bank loan due 2018	**—**	72
Total including debt due within one year	**23,730**	30,234
Debt due within one year	**(5,000)**	(6,722)
Reclassified from short-term debt	**9,900**	10,000
Unamortized discounts and debt issuance costs	**(24)**	(35)
Capital lease obligations[4]	**127**	94
Total long-term debt	**$ 28,733**	$ 33,571

[1] Weighted-average interest rate at December 31, 2018.
[2] Interest rate at December 31, 2018.
[3] Maturity date is conditional upon the occurrence of certain events. 2021 is the earliest period in which the loan may become payable.
[4] For details on capital lease obligations, see Note 5 beginning on page 62.

Chevron has an automatic shelf registration statement that expires in May 2021. This registration statement is for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

Long-term debt excluding capital lease obligations with a principal balance of $23,730 matures as follows: 2019 – $5,000; 2020 – $5,054; 2021 – $2,272; 2022 – $4,050; 2023 – $3,003; and after 2023 – $4,351.

See Note 8, beginning on page 63, for information concerning the fair value of the company's long-term debt.

Note 20
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, 2018:

	2018	2017	2016
Beginning balance at January 1	**$ 3,702**	$ 3,540	$ 3,312
Additions to capitalized exploratory well costs pending the determination of proved reserves	**207**	323	465
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(13)**	(113)	(119)
Capitalized exploratory well costs charged to expense	**(333)**	(39)	(118)
Other reductions*	**—**	(9)	—
Ending balance at December 31	**$ 3,563**	$ 3,702	$ 3,540

* 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		
	2018	2017	2016
Exploratory well costs capitalized for a period of one year or less	**$ 202**	$ 307	$ 445
Exploratory well costs capitalized for a period greater than one year	**3,361**	3,395	3,095
Balance at December 31	**$ 3,563**	$ 3,702	$ 3,540
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**30**	32	35

* Certain projects have multiple wells or fields or both.

Of the $3,361 of exploratory well costs capitalized for more than one year at December 31, 2018, $1,585 (14 projects) is related to projects that had drilling activities underway or firmly planned for the near future. The $1,776 balance is related to 16 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 $1,776 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $672 (three projects) – undergoing front-end engineering and design with final investment decision expected within four years; (b) $93 (one project) – development concept under review by government; (c) $963 (eight projects) – development alternatives under review; (d) $48 (four projects) – miscellaneous activities for projects with smaller amounts suspended. While progress was being made on all 30 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 $3,361 of suspended well costs capitalized for a period greater than one year as of December 31, 2018, represents 153 exploratory wells in 30 projects. The tables below contain the aging of these costs on a well and project basis:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1998-2007	$ 410	31
2008-2012	1,076	61
2013-2017	1,875	61
Total	**$ 3,361**	**153**

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
2003-2010	$ 338	5
2011-2014	894	10
2015-2018	2,129	15
Total	**$ 3,361**	**30**

Note 21

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2018, 2017 and 2016 was $105 ($83 after tax), $137 ($89 after tax) and $271 ($176 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance shares and restricted stock units was $60 ($47 after tax), $231 ($150 after tax) and $371 ($241 after tax) for 2018, 2017 and 2016, respectively. No significant stock-based compensation cost was capitalized at December 31, 2018, or December 31, 2017.

Cash received in payment for option exercises under all share-based payment arrangements for 2018, 2017 and 2016 was $1,159, $1,100 and $647, respectively. Actual tax benefits realized for the tax deductions from option exercises were $43, $48 and $21 for 2018, 2017 and 2016, respectively.

Cash paid to settle performance shares, restricted stock units and stock appreciation rights was $157, $187 and $82 for 2018, 2017 and 2016, 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, five 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 2018, 2017 and 2016 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2018	2017	2016
Expected term in years[1]	**6.5**	6.3	6.3
Volatility[2]	**21.2 %**	21.7 %	21.7 %
Risk-free interest rate based on zero coupon U.S. treasury note	**2.6 %**	2.2 %	1.6 %
Dividend yield	**3.8 %**	4.2 %	4.5 %
Weighted-average fair value per option granted	**$ 18.18**	$ 15.31	$ 9.53

[1] Expected term is based on historical exercise and post-vesting 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 2018 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Averaged Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at January 1, 2018	103,765	$ 97.40		
Granted	4,665	$ 125.35		
Exercised	(12,991)	$ 88.11		
Forfeited	(715)	$ 115.25		
Outstanding at December 31, 2018	94,724	$ 99.92	5.07	$ 1,101
Exercisable at December 31, 2018	81,074	$ 99.34	4.60	$ 933

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2018, 2017 and 2016 was $506, $407 and $240, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2018, there was $53 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 1.6 years.

At January 1, 2018, the number of LTIP performance shares outstanding was equivalent to 3,090,793 shares. During 2018, 1,491,141 performance shares were granted, 746,450 shares vested with cash proceeds distributed to recipients and 165,754 shares were forfeited. At December 31, 2018, performance shares outstanding were 3,669,730. The fair value of the liability recorded for these instruments was $258, and was measured using the Monte Carlo simulation method.

At January 1, 2018, the number of restricted stock units outstanding was equivalent to 1,236,500 shares. During 2018, 819,769 restricted stock units were granted, 222,946 units vested with cash proceeds distributed to recipients and 95,844 units were forfeited. At December 31, 2018, restricted stock units outstanding were 1,737,479. The fair value of the liability recorded for the vested portion of these instruments was $125, valued at the stock price as of December 31, 2018. In addition, outstanding stock appreciation rights that were granted under LTIP totaled approximately 4.2 million equivalent shares as of December 31, 2018. The fair value of the liability recorded for the vested portion of these instruments was $70.

Note 22
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. For the company's main U.S. medical plan, 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 2018 and 2017 follows:

	Pension Benefits				Other Benefits	
	2018		2017			
	U.S.	**Int'l.**	U.S.	Int'l.	**2018**	2017
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 13,580**	**$ 5,540**	$ 13,271	$ 5,169	**$ 2,788**	$ 2,549
Service cost	**480**	**141**	489	151	**42**	32
Interest cost	**370**	**206**	366	219	**94**	95
Plan participants' contributions	**—**	**4**	—	4	**71**	78
Plan amendments	**—**	**23**	—	1	**2**	—
Actuarial (gain) loss	**(1,051)**	**(239)**	1,168	(37)	**(272)**	266
Foreign currency exchange rate changes	**—**	**(227)**	—	374	**(9)**	10
Benefits paid	**(1,653)**	**(432)**	(1,714)	(310)	**(237)**	(229)
Divestitures	**—**	**(196)**	—	(31)	**(49)**	(13)
Benefit obligation at December 31	**11,726**	**4,820**	13,580	5,540	**2,430**	2,788
Change in Plan Assets						
Fair value of plan assets at January 1	**9,948**	**4,766**	9,550	4,174	**—**	—
Actual return on plan assets	**(566)**	**(9)**	1,384	319	**—**	—
Foreign currency exchange rate changes	**—**	**(221)**	—	358	**—**	—
Employer contributions	**803**	**232**	728	252	**166**	151
Plan participants' contributions	**—**	**4**	—	4	**71**	78
Benefits paid	**(1,653)**	**(432)**	(1,714)	(310)	**(237)**	(229)
Divestitures	**—**	**(198)**	—	(31)	**—**	—
Fair value of plan assets at December 31	**8,532**	**4,142**	9,948	4,766	**—**	—
Funded status at December 31	**$ (3,194)**	**$ (678)**	$ (3,632)	$ (774)	**$ (2,430)**	$ (2,788)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and OPEB plans at December 31, 2018 and 2017, include:

	Pension Benefits				Other Benefits	
	2018		2017			
	U.S.	**Int'l.**	U.S.	Int'l.	**2018**	2017
Deferred charges and other assets	**$ 17**	**$ 412**	$ 21	$ 448	**$ —**	$ —
Accrued liabilities	**(180)**	**(66)**	(188)	(100)	**(175)**	(174)
Noncurrent employee benefit plans	**(3,031)**	**(1,024)**	(3,465)	(1,122)	**(2,255)**	(2,614)
Net amount recognized at December 31	**$ (3,194)**	**$ (678)**	$ (3,632)	$ (774)	**$ (2,430)**	$ (2,788)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were $4,448 and $5,286 at the end of 2018 and 2017, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2018		2017			
	U.S.	**Int'l.**	U.S.	Int'l.	**2018**	2017
Net actuarial loss	**$ 3,694**	**$ 955**	$ 4,258	$ 1,005	**$ (56)**	$ 207
Prior service (credit) costs	**7**	**104**	9	94	**(256)**	(287)
Total recognized at December 31	**$ 3,701**	**$ 1,059**	$ 4,267	$ 1,099	**$ (312)**	$ (80)

The accumulated benefit obligations for all U.S. and international pension plans were $10,514 and $4,360, respectively, at December 31, 2018, and $12,194 and $5,009, respectively, at December 31, 2017.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2018 and 2017, was:

	Pension Benefits			
	2018		2017	
	U.S.	**Int'l.**	U.S.	Int'l.
Projected benefit obligations	**$ 11,667**	**$ 1,277**	$ 13,514	$ 1,590
Accumulated benefit obligations	**10,456**	**1,062**	12,129	1,326
Fair value of plan assets	**8,456**	**198**	9,862	413

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2018, 2017 and 2016 are shown in the table below:

	Pension Benefits						Other Benefits		
	2018		2017		2016				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2018**	2017	2016
Net Periodic Benefit Cost									
Service cost	**$ 480**	**$ 141**	$ 489	$ 151	$ 494	$ 159	**$ 42**	$ 32	$ 60
Interest cost	**370**	**206**	366	219	377	261	**94**	95	128
Expected return on plan assets	**(636)**	**(253)**	(597)	(239)	(723)	(243)	**—**	—	—
Amortization of prior service costs (credits)	**2**	**10**	(5)	13	(9)	14	**(28)**	(28)	14
Recognized actuarial losses	**304**	**29**	340	44	335	47	**15**	(5)	19
Settlement losses	**411**	**33**	436	2	511	6	**—**	—	—
Curtailment losses (gains)	**—**	**3**	—	—	—	—	**—**	—	—
Total net periodic benefit cost	**931**	**169**	1,029	190	985	244	**123**	94	221
Changes Recognized in Comprehensive Income									
Net actuarial (gain) loss during period	**151**	**12**	381	(94)	690	55	**(248)**	284	(430)
Amortization of actuarial loss	**(715)**	**(62)**	(776)	(46)	(846)	(53)	**(15)**	5	(19)
Prior service (credits) costs during period	**—**	**23**	—	1	—	—	**3**	—	(345)
Amortization of prior service (costs) credits	**(2)**	**(13)**	5	(13)	9	(14)	**28**	28	(14)
Total changes recognized in other comprehensive income	**(566)**	**(40)**	(390)	(152)	(147)	(12)	**(232)**	317	(808)
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 365**	**$ 129**	$ 639	$ 38	$ 838	$ 232	**$ (109)**	$411	$ (587)

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2018, 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 13 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 2019, the company estimates actuarial losses of $239, $19 and $(3) 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 $290 will be recognized from "Accumulated other comprehensive loss" during 2019 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, 2018, was approximately 4 and 8 years for U.S. and international pension plans, respectively, and 8 years for OPEB plans. During 2019, the company estimates prior service (credits) costs of $2, $12 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		
	2018		2017		2016				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2018**	2017	2016
Assumptions used to determine benefit obligations:									
Discount rate	**4.2%**	**4.4%**	3.5%	3.9%	3.9%	4.3%	**4.4%**	3.8%	4.3%
Rate of compensation increase	**4.5%**	**4.0%**	4.5%	4.0%	4.5%	4.5%	**N/A**	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate for service cost	**3.7%**	**3.9%**	4.2%	4.3%	4.4%	5.3%	**3.9%**	4.6%	4.9%
Discount rate for interest cost	**3.0%**	**3.9%**	3.0%	4.3%	3.0%	5.3%	**3.5%**	3.8%	4.0%
Expected return on plan assets	**6.8%**	**5.5%**	6.8%	5.5%	7.3%	6.3%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**4.0%**	4.5%	4.5%	4.5%	4.8%	**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 2018, the company used an expected long-term rate of return of 6.75 percent for U.S. pension plan assets, which account for 67 percent of the company's pension plan assets. In 2017, the company used a long-term rate of return of 6.75 percent for these plans, and in 2016, 7.25 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 2018 were 4.2 percent for the main U.S. pension plan and 4.3 percent for the main U.S. OPEB plan. The discount rates for these plans at the end of 2017 were 3.5 and 3.6 percent, respectively, while in 2016 they were 3.9 and 4.1 percent for these plans, respectively.

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, 2018, for the main U.S. OPEB plan, the assumed health care cost-trend rates start with 7.2 percent in 2019 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2017, the assumed health care cost-trend rates started with 7.4 percent in 2018 and gradually declined to 4.5 percent for 2025 and beyond. 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	$ 197	$ (156)

Plan Assets and Investment Strategy

The fair value measurements of the company's pension plans for 2018 and 2017 are on the following page:

	U.S.					Int'l.				
	Total	Level 1	Level 2	Level 3	NAV	Total	Level 1	Level 2	Level 3	NAV
At December 31, 2017										
Equities										
U.S.[1]	$ 1,331	$ 1,331	$ —	$ —	—	$ 652	$ 651	$ 1	$ —	$ —
International	2,060	2,057	3	—	—	691	691	—	—	—
Collective Trusts/Mutual Funds[2]	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[2]	1,130	—	—	—	1,130	1,481	—	16	—	1,465
Mixed Funds[3]	—	—	—	—	—	80	1	79	—	—
Real Estate[4]	1,096	—	—	—	1,096	376	—	—	56	320
Alternative Investments[5]	1,022	—	—	—	1,022	—	—	—	—	—
Cash and Cash Equivalents	260	255	5	—	—	366	362	4	—	—
Other[6]	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
At December 31, 2018										
Equities										
U.S.[1]	**$ 1,110**	**$ 1,110**	**$ —**	**$ —**	**$ —**	**$ 520**	**$ 520**	**$ —**	**$ —**	**$ —**
International	**1,631**	**1,630**	**1**	**—**	**—**	**521**	**520**	**—**	**1**	**—**
Collective Trusts/Mutual Funds[2]	**893**	**21**	**—**	**—**	**872**	**152**	**9**	**—**	**—**	**143**
Fixed Income										
Government	**225**	**—**	**225**	**—**	**—**	**254**	**97**	**157**	**—**	**—**
Corporate	**1,382**	**—**	**1,382**	**—**	**—**	**409**	**—**	**389**	**20**	**—**
Bank Loans	**119**	**—**	**114**	**5**	**—**	**—**	**—**	**—**	**—**	**—**
Mortgage/Asset Backed	**1**	**—**	**1**	**—**	**—**	**6**	**—**	**6**	**—**	**—**
Collective Trusts/Mutual Funds[2]	**877**	**—**	**—**	**—**	**877**	**1,521**	**15**	**—**	**—**	**1,506**
Mixed Funds[3]	**—**	**—**	**—**	**—**	**—**	**74**	**3**	**71**	**—**	**—**
Real Estate[4]	**1,065**	**—**	**—**	**—**	**1,065**	**378**	**—**	**—**	**56**	**322**
Alternative Investments[5]	**941**	**—**	**—**	**—**	**941**	**—**	**—**	**—**	**—**	**—**
Cash and Cash Equivalents	**212**	**208**	**4**	**—**	**—**	**287**	**277**	**2**	**—**	**8**
Other[6]	**76**	**(4)**	**31**	**44**	**5**	**20**	**—**	**17**	**3**	**—**
Total at December 31, 2018	**$ 8,532**	**$ 2,965**	**$ 1,758**	**$ 49**	**$ 3,760**	**$ 4,142**	**$ 1,441**	**$ 642**	**$ 80**	**$ 1,979**

1 U.S. equities include investments in the company's common stock in the amount of $9 at December 31, 2018, and $12 at December 31, 2017.
2 Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly unit trust and index funds.
3 Mixed funds are composed of funds that invest in both equity and fixed-income instruments in order to diversify and lower risk.
4 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.
5 Alternative investments focus on market-neutral strategies that have a low expected correlation to traditional asset classes.
6 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:

	Equity	Fixed Income				
	International	Corporate	Bank Loans	Real Estate	Other	Total
Total at December 31, 2016	$ —	$ 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
Actual Return on Plan Assets:						
Assets held at the reporting date	**4**	**(2)**	**—**	**13**	**—**	**15**
Assets sold during the period	**(4)**	**—**	**—**	**—**	**—**	**(4)**
Purchases, Sales and Settlements	**—**	**(7)**	**(4)**	**(13)**	**—**	**(24)**
Transfers in and/or out of Level 3	**1**	**—**	**(2)**	**—**	**—**	**(1)**
Total at December 31, 2018	**$ 1**	**$ 21**	**$ 5**	**$ 56**	**$ 46**	**$ 129**

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 91 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 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 25–45 percent, Fixed Income and Cash 40–75 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 2018, the company contributed $803 and $232 to its U.S. and international pension plans, respectively. In 2019, the company expects contributions to be approximately $700 to its U.S. plans and $200 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 $175 in 2019; $166 was paid in 2018.

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
	U.S.	Int'l.	Benefits
2019	$ 1,310	$ 271	$ 175
2020	$ 1,240	$ 266	$ 172
2021	$ 1,170	$ 577	$ 171
2022	$ 1,145	$ 228	$ 168
2023	$ 1,118	$ 234	$ 166
2024-2028	$ 4,972	$ 1,392	$ 795

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 $270, $316 and $281 in 2018, 2017 and 2016, 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 2018, 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, 2018 and 2017, trust assets of $34 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 $1,048, $936 and $662 in 2018, 2017 and 2016, 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 21, beginning on page 80.

Note 23
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 16, beginning on page 74, 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.

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 provisions have been made for all years under examination or subject to future examination.

Guarantees The company has two guarantees to equity affiliates totaling $968. Of this amount, $637 is associated with a financing arrangement with an equity affiliate. Over the approximate 3-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of $331 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 9-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, drill ships, 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: 2019 – $1,300; 2020 – $1,200; 2021 – $1,300; 2022 – $1,000; 2023 – $800; 2023 and after – $4,700. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $1,400 in 2018, $1,300 in 2017 and $1,300 in 2016.

As part of the implementation of ASU 2016-02 (Topic 842) effective January 1, 2019, the company will reclassify some contracts, currently incorporated into the unconditional purchase obligations disclosure, as operating leases in first quarter 2019 results.

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, 2018, was $1,327. Included in this balance was $258 related to remediation activities at approximately 144 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 2018 environmental reserves balance of $1,069, $748 is related to the company's U.S. downstream operations, $24 to its international downstream operations, $296 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 2018 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

Refer to Note 24 on page 88 for a discussion of the company's asset retirement obligations.

Other Contingencies Governmental and other entities in California and other jurisdictions have filed legal proceedings against fossil fuel producing companies, including Chevron, purporting to seek legal and equitable relief to address alleged impacts of climate change. Further such proceedings are likely to be filed by other parties. The unprecedented legal theories set forth in these proceedings entail the possibility of damages liability and injunctions against the production of all fossil fuels that, while we believe remote, could have a material adverse effect on the company's results of operations and financial condition. Management believes that these proceedings are legally and factually meritless and detract from constructive efforts to address the important policy issues presented by climate change, and will vigorously defend against such proceedings.

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 24
Asset Retirement Obligations

The company records the fair value of a liability for an asset retirement obligation (ARO) both as an asset and a 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 2018, 2017 and 2016:

	2018	2017	2016
Balance at January 1	**$ 14,214**	$ 14,243	$ 15,642
Liabilities incurred	**96**	684	204
Liabilities settled	**(830)**	(1,721)	(1,658)
Accretion expense	**654**	668	749
Revisions in estimated cash flows	**(84)**	340	(694)
Balance at December 31	**$ 14,050**	$ 14,214	$ 14,243

In the table above, the amount associated with "Revisions in estimated cash flows" in 2018 reflects decreased cost estimates to abandon wells, equipment and facilities. The long-term portion of the $14,050 balance at the end of 2018 was $12,957.

Note 25
Revenue

On January 1, 2018, Chevron adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and its related amendments using the modified retrospective transition method, which did not require the restatement of prior periods. The adoption did not result in a material change in the company's accounting or have a material effect on the company's financial position, including the measurement of revenue, the timing of revenue recognition and the recognition of contract assets, liabilities and related costs.

The most significant change is the presentation of excise, value-added and similar taxes collected on behalf of third parties, which are no longer presented within "Sales and other operating revenue" on the Consolidated Statement of Income starting in 2018. These taxes, which totaled $7,861 in 2018, are now netted in "Taxes other than on income" on the Consolidated Statement of Income. This change to presentation had no impact on earnings. These taxes totaled $7,189 and $6,905 in 2017 and 2016, respectively.

The company applied the optional exemption to not report any unfulfilled performance obligations related to contracts that have terms of less than one year. The amount of future revenue for unfulfilled performance obligations under long-term contracts with fixed components was insignificant for the year ended December 31, 2018.

Revenue from contracts with customers is presented in "Sales and other operating revenue" along with some activity that is accounted for outside the scope of ASC 606, which is not material to this line, on the Consolidated Statement of Income. 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. Refer to Note 13 beginning on page 66 for additional information on the company's segmentation of revenue.

Receivables related to revenue from contracts with customers are included in "Accounts and notes receivable, net" on the Consolidated Balance Sheet, net of the allowance for doubtful accounts. The net balance of these receivables was $9,779 and $10,046 at January 1, 2018 and December 31, 2018, respectively. Other items included in "Accounts and notes receivable, net" represent amounts due from partners for their share of joint venture operating and project costs and amounts due from others, primarily related to derivatives, leases, buy/sell arrangements and product exchanges, which are accounted for outside the scope of ASC 606.

Contract assets and related costs are reflected in “Prepaid expenses and other current assets” and contract liabilities are reflected in “Accrued liabilities” and “Deferred credits and other noncurrent obligations” on the Consolidated Balance Sheet. Amounts for these items are not material to the company’s financial position.

Note 26

Other Financial Information

Earnings in 2018 included after-tax gains of approximately $630 relating to the sale of certain properties. Of this amount, approximately $365 and $265 related to downstream and upstream, respectively. Earnings in 2017 included after-tax gains of approximately $1,800 relating to the sale of certain properties, of which approximately $850 and $950 related to downstream and upstream assets, respectively. Earnings in 2018 included after-tax charges of approximately $2,000 for impairments and other asset write-offs related to upstream. Earnings in 2017 included after-tax charges of approximately $900 for impairments and other asset write-offs related to upstream.

Other financial information is as follows:

	Year ended December 31		
	2018	2017	2016
Total financing interest and debt costs	**$ 921**	$ 902	$ 753
Less: Capitalized interest	**173**	595	552
Interest and debt expense	**$ 748**	$ 307	$ 201
Research and development expenses	**$ 453**	$ 433	$ 476
Excess of replacement cost over the carrying value of inventories (LIFO method)	**$ 5,134**	$ 3,937	$ 2,942
LIFO profits (losses) on inventory drawdowns included in earnings	**$ 26**	$ (5)	$ (88)
Foreign currency effects*	**$ 611**	$ (446)	$ 58

* Includes $416, $(45) and $1 in 2018, 2017 and 2016, respectively, for the company’s share of equity affiliates’ foreign currency effects.

The company has $4,518 in goodwill on the Consolidated Balance Sheet, all of which is in the upstream segment and primarily related to the 2005 acquisition of Unocal. The company tested this goodwill for impairment during 2018, and no impairment was required.

Five-Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts	**2018**	2017	2016	2015	2014
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	**$ 158,902**	$ 134,674	$ 110,215	$ 129,925	$ 200,494
Income from equity affiliates and other income	**7,437**	7,048	4,257	8,552	11,476
Total Revenues and Other Income	**166,339**	141,722	114,472	138,477	211,970
Total Costs and Other Deductions	**145,764**	132,501	116,632	133,635	180,768
Income Before Income Tax Expense (Benefit)	**20,575**	9,221	(2,160)	4,842	31,202
Income Tax Expense (Benefit)	**5,715**	(48)	(1,729)	132	11,892
Net Income	**14,860**	9,269	(431)	4,710	19,310
Less: Net income attributable to noncontrolling interests	**36**	74	66	123	69
Net Income (Loss) Attributable to Chevron Corporation	**$ 14,824**	$ 9,195	$ (497)	$ 4,587	$ 19,241
Per Share of Common Stock					
Net Income (Loss) Attributable to Chevron					
– Basic	**$ 7.81**	$ 4.88	$ (0.27)	$ 2.46	$ 10.21
– Diluted	**$ 7.74**	$ 4.85	$ (0.27)	$ 2.45	$ 10.14
Cash Dividends Per Share	**$ 4.48**	$ 4.32	$ 4.29	$ 4.28	$ 4.21
Balance Sheet Data (at December 31)					
Current assets	**$ 34,021**	$ 28,560	$ 29,619	$ 34,430	$ 41,161
Noncurrent assets	**219,842**	225,246	230,459	230,110	223,723
Total Assets	**253,863**	253,806	260,078	264,540	264,884
Short-term debt	**5,726**	5,192	10,840	4,927	3,790
Other current liabilities	**21,445**	22,545	20,945	20,540	27,322
Long-term debt	**28,733**	33,571	35,286	33,622	23,994
Other noncurrent liabilities	**42,317**	43,179	46,285	51,565	53,587
Total Liabilities	**98,221**	104,487	113,356	110,654	108,693
Total Chevron Corporation Stockholders' Equity	**$ 154,554**	$ 148,124	$ 145,556	$ 152,716	$ 155,028
Noncontrolling interests	**1,088**	1,195	1,166	1,170	1,163
Total Equity	**$ 155,642**	$ 149,319	$ 146,722	$ 153,886	$ 156,191
* Includes excise, value-added and similar taxes:	**$ —**	$ 7,189	$ 6,905	$ 7,359	$ 8,186

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 Development[1]

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2018									
Exploration									
Wells	**$ 508**	**$ 74**	**$ 25**	**$ 55**	**$ —**	**$ 14**	**$ 676**	**$ —**	**$ —**
Geological and geophysical	**84**	**41**	**4**	**5**	**7**	**1**	**142**	**—**	**—**
Rentals and other	**190**	**46**	**35**	**33**	**49**	**23**	**376**	**—**	**—**
Total exploration	**782**	**161**	**64**	**93**	**56**	**38**	**1,194**	**—**	**—**
Property acquisitions[2]									
Proved	**160**	**—**	**7**	**117**	**—**	**—**	**284**	**—**	**—**
Unproved	**52**	**494**	**2**	**27**	**—**	**—**	**575**	**—**	**—**
Total property acquisitions	**212**	**494**	**9**	**144**	**—**	**—**	**859**	**—**	**—**
Development[3]	**6,245**	**856**	**711**	**1,095**	**845**	**278**	**10,030**	**4,883**	**200**
Total Costs Incurred[4]	**$ 7,239**	**$ 1,511**	**$ 784**	**$ 1,332**	**$ 901**	**$ 316**	**$ 12,083**	**$ 4,883**	**$ 200**
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 Incurred[4]	$ 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 Incurred[4]	$ 4,770	$ 1,725	$ 2,201	$ 2,037	$ 3,804	$ 587	$ 15,124	$ 2,211	$ 262

1 Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 24, "Asset Retirement Obligations," on page 88.
2 Does not include properties acquired in nonmonetary transactions.
3 Includes $114, $84 and $481 costs incurred on major capital projects prior to assignment of proved reserves for consolidated companies in 2018, 2017, and 2016, respectively.
4 Reconciliation of consolidated and affiliated companies total cost incurred to Upstream capital and exploratory (C&E) expenditures - $ billions:

	2018	2017	2016	
Total cost incurred	$ 17.2	$ 15.7	$ 17.6	
Non-oil and gas activities	0.6	1.3	2.5	(Primarily; LNG and transportation activities.)
ARO	(0.1)	(0.6)	—	
Upstream C&E	$ 17.7	$ 16.4	$ 20.1	Reference page 39 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 14, beginning on page 69, for a discussion of the company's major equity affiliates.

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

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
At December 31, 2018									
Unproved properties	**$ 4,687**	**$ 2,463**	**$ 201**	**$ 1,299**	**$ 1,986**	**$ —**	**$ 10,636**	**$ 108**	**$ —**
Proved properties and related producing assets	**75,013**	**21,796**	**44,876**	**57,168**	**22,047**	**12,634**	**233,534**	**9,892**	**4,336**
Support equipment	**2,216**	**317**	**1,096**	**2,149**	**17,712**	**124**	**23,614**	**1,858**	**—**
Deferred exploratory wells	**782**	**160**	**405**	**632**	**1,323**	**261**	**3,563**	**—**	**—**
Other uncompleted projects	**4,730**	**3,704**	**1,744**	**1,292**	**1,462**	**300**	**13,232**	**11,906**	**605**
Gross Capitalized Costs	**87,428**	**28,440**	**48,322**	**62,540**	**44,530**	**13,319**	**284,579**	**23,764**	**4,941**
Unproved properties valuation	**820**	**694**	**164**	**623**	**107**	**—**	**2,408**	**61**	**—**
Proved producing properties – Depreciation and depletion	**45,712**	**12,984**	**31,102**	**43,735**	**4,631**	**10,014**	**148,178**	**5,289**	**1,730**
Support equipment depreciation	**1,466**	**220**	**738**	**1,674**	**1,531**	**119**	**5,748**	**947**	**—**
Accumulated provisions	**47,998**	**13,898**	**32,004**	**46,032**	**6,269**	**10,133**	**156,334**	**6,297**	**1,730**
Net Capitalized Costs	**$ 39,430**	**$ 14,542**	**$ 16,318**	**$ 16,508**	**$ 38,261**	**$ 3,186**	**$ 128,245**	**$ 17,467**	**$ 3,211**
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

Table III - Results of Operations for Oil and Gas Producing Activities[1]

The company's results of operations from oil and gas producing activities for the years 2018, 2017 and 2016 are shown in the following table. Net income (loss) from exploration and production activities as reported on page 67 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 67.

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2018									
Revenues from net production									
Sales	**$ 2,162**	**$ 1,008**	**$ 829**	**$ 5,880**	**$ 4,229**	**$ 619**	**$ 14,727**	**$ 5,987**	**$ 1,369**
Transfers	**11,645**	**1,808**	**7,829**	**3,206**	**3,413**	**1,071**	**28,972**	**—**	**—**
Total	**13,807**	**2,816**	**8,658**	**9,086**	**7,642**	**1,690**	**43,699**	**5,987**	**1,369**
Production expenses excluding taxes	**(3,203)**	**(1,009)**	**(1,564)**	**(2,653)**	**(557)**	**(424)**	**(9,410)**	**(447)**	**(295)**
Taxes other than on income	**(540)**	**(70)**	**(112)**	**(22)**	**(250)**	**(2)**	**(996)**	**160**	**(210)**
Proved producing properties:									
Depreciation and depletion	**(4,583)**	**(998)**	**(3,368)**	**(3,714)**	**(2,103)**	**(411)**	**(15,177)**	**(703)**	**(306)**
Accretion expense[2]	**(186)**	**(26)**	**(149)**	**(146)**	**(50)**	**(52)**	**(609)**	**(4)**	**(3)**
Exploration expenses	**(777)**	**(191)**	**(52)**	**(58)**	**(56)**	**(41)**	**(1,175)**	**—**	**(6)**
Unproved properties valuation	**(516)**	**(42)**	**(3)**	**(135)**	**—**	**—**	**(696)**	**—**	**—**
Other income (expense)[3]	**336**	**4**	**97**	**(33)**	**31**	**(161)**	**274**	**(59)**	**(280)**
Results before income taxes	**4,338**	**484**	**3,507**	**2,325**	**4,657**	**599**	**15,910**	**4,934**	**269**
Income tax (expense) benefit	**(886)**	**(400)**	**(2,131)**	**(1,088)**	**(1,415)**	**(233)**	**(6,153)**	**(1,480)**	**341**
Results of Producing Operations	**$ 3,452**	**$ 84**	**$ 1,376**	**$ 1,237**	**$ 3,242**	**$ 366**	**$ 9,757**	**$ 3,454**	**$ 610**
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

[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 24, "Asset Retirement Obligations," on page 88.

[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 Activities[1], continued

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
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) benefits	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 24, "Asset Retirement Obligations," on page 88.
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 Costs[1]

	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2018									
Average sales prices									
Liquids, per barrel	**$ 58.17**	**$ 58.27**	**$ 69.75**	**$ 63.55**	**$ 68.78**	**$ 66.31**	**$ 62.45**	**$ 56.20**	**$ 56.41**
Natural gas, per thousand cubic feet	**1.86**	**2.62**	**2.55**	**4.48**	**8.78**	**7.54**	**5.54**	**0.77**	**3.19**
Average production costs, per barrel[2]	**11.18**	**17.32**	**11.29**	**12.15**	**3.95**	**14.21**	**10.78**	**3.59**	**9.29**
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

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

	2018			2017			2016		
Liquids in Millions of Barrels Natural Gas in Billions of Cubic Feet	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas
Proved Developed									
Consolidated Companies									
U.S.	**1,240**	**—**	**2,396**	1,031	—	2,096	992	—	2,102
Other Americas	**159**	**545**	**393**	101	543	398	92	601	533
Africa	**628**	**—**	**1,316**	664	—	1,276	640	—	1,039
Asia	**470**	**—**	**4,021**	529	—	4,463	621	—	4,962
Australia/Oceania	**132**	**—**	**10,084**	126	—	9,907	124	—	9,176
Europe	**84**	**—**	**205**	83	—	215	77	—	213
Total Consolidated	**2,713**	**545**	**18,415**	2,534	543	18,355	2,546	601	18,025
Affiliated Companies									
TCO	**700**	**—**	**1,179**	787	—	1,300	920	—	1,402
Other	**76**	**55**	**308**	84	66	270	92	62	319
Total Consolidated and Affiliated Companies	**3,489**	**600**	**19,902**	3,405	609	19,925	3,558	663	19,746
Proved Undeveloped									
Consolidated Companies									
U.S.	**1,162**	**—**	**4,313**	885	—	3,084	420	—	1,574
Other Americas	**204**	**—**	**470**	196	—	397	131	3	114
Africa	**148**	**—**	**1,499**	175	—	1,630	236	—	1,788
Asia	**109**	**—**	**289**	102	—	310	99	—	571
Australia/Oceania	**29**	**—**	**3,647**	33	—	3,652	34	—	3,339
Europe	**65**	**—**	**100**	62	—	86	61	—	21
Total Consolidated	**1,717**	**—**	**10,318**	1,453	—	9,159	981	3	7,407
Affiliated Companies									
TCO	**905**	**—**	**755**	962	—	883	989	—	840
Other	**7**	**72**	**601**	20	93	769	26	108	767
Total Consolidated and Affiliated Companies	**2,629**	**72**	**11,674**	2,435	93	10,811	1,996	111	9,014
Total Proved Reserves	**6,118**	**672**	**31,576**	5,840	702	30,736	5,554	774	28,760

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 company 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. Proved undeveloped reserves are the quantities expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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 overseeing 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 *Chevron Corporation 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 senior leadership team including 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 *Chevron Corporation Reserves Manual.*

Technologies Used in Establishing Proved Reserves Additions In 2018, 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 2018, proved undeveloped reserves totaled 4.6 billion barrels of oil-equivalent (BOE), an increase of 317 million BOE from year-end 2017. The increase was due to 717 million BOE in extensions and discoveries, 69 million BOE in acquisitions, 58 million BOE in revisions and 6 million BOE in improved recovery, partially offset by the transfer of 531 million BOE to proved developed and 2 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 2018, investments totaling approximately $10 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 $4.8 billion, primarily related to development projects of the TCO affiliate in Kazakhstan. The United States accounted for about $3.4 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 and Argentina were primarily responsible for about $0.9 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 2018, the company held approximately 2.1 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 operating constraints and infrastructure optimization. In Africa, approximately 300 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 1.2 billion BOE of proved undeveloped reserves with about 900 million 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 and facility constraints.

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 2018, 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 2018, 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.

Proved Reserve Quantities For the three years ending December 31, 2018, 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, 2018, proved reserves for the company were 12.1 billion BOE. The company's estimated net proved reserves of liquids including crude oil, condensate, natural gas liquids and synthetic oil for the years 2016, 2017 and 2018 are shown in the table on page 98. The company's estimated net proved reserves of natural gas are shown on page 99.

Noteworthy changes in liquids proved reserves for 2016 through 2018 are discussed below and shown in the table on the following page:

Revisions In 2016, 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. Entitlement effects were mainly responsible for the 64 million barrel increase in the TCO affiliate in Kazakhstan. 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.

In 2018, improved field performance at various Gulf of Mexico fields and in the Midland and Delaware basins were primarily responsible for the 155 million barrel increase in the United States. Improved field performance at various fields, including Agbami in Nigeria and Moho-Bilondo in the Republic of Congo, were responsible for the 68 million barrel increase in Africa. Reserves in Other Americas increased by 60 million barrels, primarily due to improved field performance at the Hebron field in Canada. In Asia, improved performance across numerous assets resulted in the 37 million barrel increase. In the TCO affiliate in Kazakhstan, entitlement effects were mainly responsible for the 39 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 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.

In 2018, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 532 million barrel increase in the United States. Extensions and discoveries in the Duvernay Shale in Canada and Loma Campana in Argentina were primarily responsible for the 36 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.

In 2018, purchases of 50 million barrels in the United States were primarily in the Midland and Delaware basins.

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.

In 2018, sales of 32 million barrels in the United States were primarily in the San Joaquin Valley.

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

	Consolidated Companies								Affiliated Companies			Total Consolidated and Affiliated Companies
Millions of barrels	U.S.	Other Americas[1]	Africa	Asia	Australia/ Oceania	Europe	Synthetic Oil[2]	Total	TCO	Synthetic Oil	Other[3]	
Reserves at January 1, 2016	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, 2016[4]	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, 2017[4]	1,916	297	839	631	159	145	543	4,530	1,749	159	104	6,542
Changes attributable to:												
Revisions	**155**	**60**	**68**	**37**	**17**	**20**	**21**	**378**	**(39)**	**(23)**	**(10)**	**306**
Improved recovery	**5**	**—**	**—**	**1**	**—**	**4**	**—**	**10**	**—**	**—**	**—**	**10**
Extensions and discoveries	**532**	**36**	**1**	**—**	**—**	**—**	**—**	**569**	**—**	**—**	**—**	**569**
Purchases	**50**	**—**	**—**	**—**	**—**	**—**	**—**	**50**	**—**	**—**	**—**	**50**
Sales	**(32)**	**—**	**(5)**	**—**	**—**	**—**	**—**	**(37)**	**—**	**—**	**—**	**(37)**
Production	**(224)**	**(30)**	**(127)**	**(90)**	**(15)**	**(20)**	**(19)**	**(525)**	**(105)**	**(9)**	**(11)**	**(650)**
Reserves at December 31, 2018[4]	**2,402**	**363**	**776**	**579**	**161**	**149**	**545**	**4,975**	**1,605**	**127**	**83**	**6,790**

1 Ending reserve balances in North America were 291, 234 and 169 and in South America were 72, 63 and 54 in 2018, 2017 and 2016, respectively.

2 Reserves associated with Canada.

3 Ending reserve balances in Africa were 19, 26 and 31 and in South America were 64, 78 and 87 in 2018, 2017 and 2016, respectively.

4 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to glossary of energy and financial terms for the definition of a PSC). PSC-related reserve quantities are 12 percent, 15 percent and 19 percent for consolidated companies for 2018, 2017 and 2016, respectively.

Net Proved Reserves of Natural Gas

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
Billions of cubic feet (BCF)	U.S.	Other Americas[1]	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other[2]	
Reserves at January 1, 2016	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, 2016[4]	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, 2017[4]	5,180	795	2,906	4,773	13,559	301	27,514	2,183	1,039	30,736
Changes attributable to:										
Revisions	**258**	**(3)**	**25**	**347**	**1,012**	**68**	**1,707**	**(108)**	**(38)**	**1,561**
Improved recovery	**2**	**2**	**—**	**—**	**1**	**—**	**5**	**—**	**—**	**5**
Extensions and discoveries	**1,627**	**138**	**—**	**5**	**—**	**1**	**1,771**	**—**	**3**	**1,774**
Purchases	**144**	**—**	**1**	**—**	**—**	**—**	**145**	**—**	**—**	**145**
Sales	**(125)**	**—**	**(5)**	**—**	**—**	**—**	**(130)**	**—**	**—**	**(130)**
Production[3]	**(377)**	**(69)**	**(112)**	**(815)**	**(841)**	**(65)**	**(2,279)**	**(141)**	**(95)**	**(2,515)**
Reserves at December 31, 2018[4]	**6,709**	**863**	**2,815**	**4,310**	**13,731**	**305**	**28,733**	**1,934**	**909**	**31,576**

1 Ending reserve balances in North America and South America were 582, 478, 172 and 281, 317, 475 in 2018, 2017 and 2016, respectively.

2 Ending reserve balances in Africa and South America were 799, 899, 939 and 110, 140, 147 in 2018, 2017 and 2016, respectively.

3 Total "as sold" volumes are 2,289, 1,995 and 1,744 for 2018, 2017 and 2016, respectively.

4 Includes reserve quantities related to production-sharing contracts (PSC) (refer to glossary of energy and financial terms for the definition of a PSC). PSC-related reserve quantities are 10 percent, 12 percent and 15 percent for consolidated companies for 2018, 2017 and 2016, respectively.

Noteworthy changes in natural gas proved reserves for 2016 through 2018 are discussed below and shown in the table above:

Revisions 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.

In 2018, reservoir performance, well test and surveillance data at Wheatstone and the greater Gorgon area were responsible for the 1.0 TCF increase in Australia. The Bibiyana Field in Bangladesh and the Pattani Field in Thailand were primarily responsible for the 347 BCF increase in Asia. Improved performance in the Midland and Delaware basins were primarily responsible for the 258 BCF increase in the United States.

Extensions and Discoveries 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.

In 2018, extensions and discoveries of 1.6 TCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins.

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.

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other	
At December 31, 2018										
Future cash inflows from production	**$ 132,512**	**$ 52,470**	**$ 56,856**	**$ 54,012**	**$ 109,116**	**$ 11,959**	**$ 416,925**	**$ 100,518**	**$ 16,928**	**$ 534,371**
Future production costs	**(34,679)**	**(20,691)**	**(18,850)**	**(17,359)**	**(16,296)**	**(6,609)**	**(114,484)**	**(24,580)**	**(4,665)**	**(143,729)**
Future development costs	**(17,322)**	**(5,106)**	**(4,112)**	**(5,494)**	**(7,757)**	**(1,393)**	**(41,184)**	**(14,069)**	**(1,692)**	**(56,945)**
Future income taxes	**(17,369)**	**(7,553)**	**(23,593)**	**(14,514)**	**(25,519)**	**(1,676)**	**(90,224)**	**(18,561)**	**(4,496)**	**(113,281)**
Undiscounted future net cash flows	**63,142**	**19,120**	**10,301**	**16,645**	**59,544**	**2,281**	**171,033**	**43,308**	**6,075**	**220,416**
10 percent midyear annual discount for timing of estimated cash flows	**(29,103)**	**(11,136)**	**(2,646)**	**(4,822)**	**(28,276)**	**(419)**	**(76,402)**	**(22,025)**	**(2,662)**	**(101,089)**
Standardized Measure Net Cash Flows	**$ 34,039**	**$ 7,984**	**$ 7,655**	**$ 11,823**	**$ 31,268**	**$ 1,862**	**$ 94,631**	**$ 21,283**	**$ 3,413**	**$ 119,327**
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

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."

Millions of dollars	Consolidated Companies	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2016	$ 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
Sales and transfers of oil and gas produced net of production costs	**(33,535)**	**(6,813)**	**(40,348)**
Development costs incurred	**9,723**	**5,044**	**14,767**
Purchases of reserves	**99**	**—**	**99**
Sales of reserves	**(622)**	**—**	**(622)**
Extensions, discoveries and improved recovery less related costs	**5,503**	**14**	**5,517**
Revisions of previous quantity estimates	**15,480**	**(2,255)**	**13,225**
Net changes in prices, development and production costs	**39,241**	**17,251**	**56,492**
Accretion of discount	**9,413**	**2,084**	**11,497**
Net change in income tax	**(16,518)**	**(4,795)**	**(21,313)**
Net change for 2018	**28,784**	**10,530**	**39,314**
Present Value at December 31, 2018	**$ 94,631**	**$24,696**	**$119,327**

our history

we are proud of chevron's 140-year history and are committed to upholding our legacy by providing the affordable, reliable, ever-cleaner energy that enables human progress

1879

Incorporated in San Francisco, California, as the Pacific Coast Oil Company.

1900

Acquired by the West Coast operations of John D. Rockefeller's original Standard Oil Company.

1911

Emerged as an autonomous entity — Standard Oil Company (California) — following U.S. Supreme Court decision to divide the Standard Oil conglomerate into 34 independent companies.

1926

Acquired Pacific Oil Company to become Standard Oil Company of California (Socal).

1936

Formed the Caltex Group of Companies, jointly owned by Socal and The Texas Company (later became Texaco), to combine Socal's exploration and production interests in the Middle East and Indonesia and provide an outlet for crude oil through The Texas Company's marketing network in Africa and Asia.

1947

Acquired Signal Oil Company, obtaining the Signal brand name and adding 2,000 retail stations in the western United States.

1961

Acquired Standard Oil Company (Kentucky), a major petroleum products marketer in five southeastern states, to provide outlets for crude oil from southern Louisiana and the U.S. Gulf of Mexico, where the company was a major producer.

1984

Acquired Gulf Corporation — nearly doubling the company's crude oil and natural gas activities — and gained a significant presence in industrial chemicals, natural gas liquids and coal. Changed name to Chevron Corporation to identify with the name under which most products were marketed.

1988

Purchased Tenneco Inc.'s U.S. Gulf of Mexico crude oil and natural gas properties, becoming one of the largest U.S. natural gas producers.

1993

Formed Tengizchevroil, a joint venture with the Republic of Kazakhstan, to develop and produce the giant Tengiz Field, becoming the first major Western oil company to enter newly independent Kazakhstan.

1999

Acquired Rutherford-Moran Oil Corporation. This acquisition provided inroads to Asian natural gas markets.

2001

Merged with Texaco Inc. and changed name to ChevronTexaco Corporation. Became the second-largest U.S.-based energy company.

2002

Relocated corporate headquarters from San Francisco, California, to San Ramon, California.

2005

Acquired Unocal Corporation, an independent crude oil and natural gas exploration and production company. Unocal's upstream assets bolstered Chevron's already-strong position in the Asia-Pacific, U.S. Gulf of Mexico and Caspian regions. Changed name to Chevron Corporation to convey a clearer, stronger and more unified presence in the global marketplace.

2011

Acquired Atlas Energy, Inc., an independent U.S. developer and producer of shale gas resources. The acquired assets provided a targeted, high-quality core acreage position, primarily in the Marcellus Shale.

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, 2018.

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.

Free cash flow The cash provided by operating activities less capital expenditures.

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.

stockholder and investor information

Stock exchange listing
Chevron common stock is listed on the New York Stock Exchange. The symbol is "CVX."

Stockholder information
As of February 11, 2019, stockholders of record numbered approximately 124,000.

For questions about stock ownership, changes of address and dividend reinvestment programs, please contact Chevron's Stock Transfer Agent:
Computershare
P.O. Box 505000
Louisville, KY 40233-5000
800 368 8357 (U.S. and Canada)
201 680 6578 (outside the U.S. and Canada)
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 a.m. PDT, Wednesday, May 29, 2019, 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 by email and vote their shares on the Internet. Stockholders of record may sign up for electronic access (and beneficial stockholders may be able to request electronic access by contacting their broker or bank or Broadridge Financial Solutions) on this website: www.icsdelivery.com/cvx/.
Enrollment is revocable until each year's Annual Meeting record date.

Investor information
Securities analysts, portfolio managers and representatives of financial institutions may contact:
Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

Notice
As used in this report, the term "Chevron" and such terms as "the company," "the corporation," "our," "we," "us" and "its" 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
San Ramon, CA 94583-2324
925 842 1000

Mike Wirth sat down with CNBC in March 2018 to discuss his priorities for the year after having been named CEO and chairman.

thai cave rescue demonstrates the chevron way
Sixteen Chevron employees and 18 contractors mobilized to the cave site and were supported by nearly 100 employees and contractors working around the clock as part of the Emergency Management Team.

In addition to personnel, Chevron also provided much-needed equipment. Within 24 hours of the Thai Navy SEALs' request for resources, Chevron committed hundreds of oxygen tanks, dozens of tank packs and a number of gas detectors to monitor air quality in various cave chambers.

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:
Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road, A3140
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

The *2018 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:
Corporate 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 2018 are available on the company's website, www.chevron.com, or by writing to:
Corporate 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*.

connect with us

This *Annual Report* contains forward-looking statements — identified by words such as "believe," "expect," "may," "will," "commit," "position," "focus," "goal," "target," "schedule," "plan," "opportunity," "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 27 for a discussion of some of the factors that could cause actual results to differ materially.

PRODUCED BY Corporate Affairs and Comptroller's Departments, Chevron Corporation
DESIGN Information Design & Communications, Chevron Corporation **PRINTING** ColorGraphics — Los Angeles, California

Chevron Corporation
6001 Bollinger Canyon Road, San Ramon, CA 94583-2324 USA
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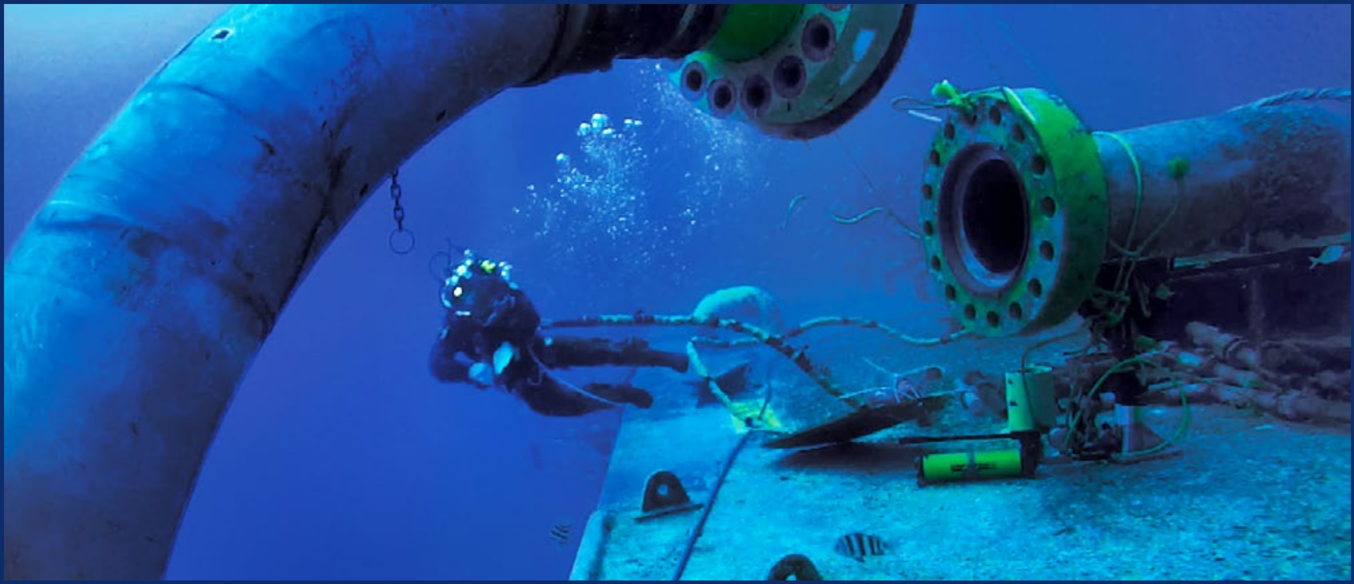
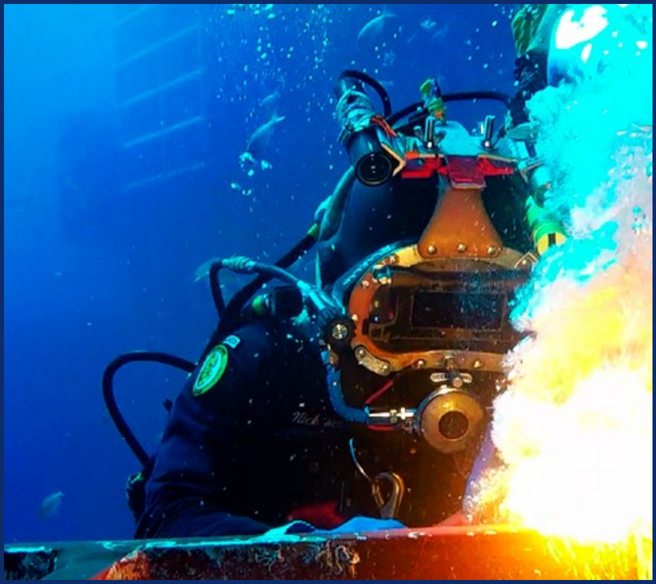
human energy®





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Cover photo: First production was achieved in November 2018 at the Big Foot deepwater project located in the U.S. Gulf of Mexico. The project is designed for a capacity of 75,000 barrels of oil and 25 million cubic feet of natural gas per day.

Inside front cover photo: Photos above show tie-in operations that took place at Big Foot prior to first production in November 2018. Big Foot is estimated to contain total potentially recoverable resources of more than 200 million oil-equivalent barrels.

2018 at a glance

financial highlights

sales and other operating revenues $158.9 billion

net income attributable to chevron corporation $14.8 billion, $7.74 per share – diluted

return on capital employed 8.2%

cash flow from operating activities $30.6 billion

cash dividends $4.48 per share

corporate strategies

Financial-return objective – Deliver industry-leading results and superior shareholder value in any business environment.

Enterprise strategies

- Invest in people to develop and empower a highly competent workforce that delivers superior results the right way.
- Deliver results through disciplined operational excellence, capital stewardship and cost efficiency.
- Grow profits and returns by using our competitive advantages.
- Differentiate performance through technology and functional expertise.

Major business strategies

- Upstream – deliver industry-leading returns while developing high-value resource opportunities.
- Downstream – 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.

accomplishments

Corporate

Safety and environment – Achieved our best safety record by maintaining industry-leading personal safety rates and outperforming all core personal safety metrics.

Dividends – Paid $8.5 billion in dividends, with 2018 marking the 31st consecutive year of higher annual dividend payouts.

Stock repurchase program – Acquired $1.75 billion of the company's shares of common stock.

Capital and exploratory expenditures – Invested $20.1 billion in the company's businesses, including $5.7 billion (Chevron share) of spending by affiliates. Announced 2019 projected expenditures of $20.0 billion, including $6.3 billion of affiliate expenditures. Spending in 2019 targets short-cycle, high-return investments, including the Permian Basin and other shale and tight plays, as well as completion of major projects underway and progression of the Future Growth and Wellhead Pressure Management Project (FGP/WPMP) at Tengizchevroil (TCO) in Kazakhstan.

Investing in the future of energy – Joined the Oil and Gas Climate Initiative and separately launched the Chevron Future Energy Fund. Both initiatives invest in technology designed to economically lower emissions.

Portfolio management – Realized $2.0 billion in proceeds from asset divestments.

Upstream

Exploration – Achieved an exploration drilling success rate of 61 percent, with 11 discoveries worldwide, and added 2.4 billion barrels of oil-equivalent resources. Made a significant crude oil discovery at the Ballymore prospect in the U.S. Gulf of Mexico. Continued shale and tight resource drilling programs in the United States, Canada and Argentina.

Portfolio additions – Added 1.3 million net exploration acres in 2018, including key positions in Brazil, the U.S. Gulf of Mexico and offshore Mexico.

Production – Record production of 2.93 million net oil-equivalent barrels per day, more than 7 percent higher than in 2017.

Shale and tight resources – Continued progress on the development of the company's significant shale and tight resource position.

- Full-year production in the Permian Basin in Texas and New Mexico increased 71 percent over the prior year.
- Transitioning from appraisal to development drilling in the Duvernay Shale in Canada.
- Initiated a shale appraisal program in November 2018 in the El Trapial Field located in the Vaca Muerta Shale in Argentina.

Major projects – Continued progress on the company's development projects to deliver future value.

- Achieved start-up of Train 2 at the Wheatstone Project in Australia.
- Commenced production at the Clair Ridge Project in the United Kingdom and the Big Foot and Stampede projects in the U.S. Gulf of Mexico.
- Achieved first oil from the Tahiti Vertical Expansion Project in the U.S. Gulf of Mexico.
- Advanced construction of the FGP/WPMP at TCO in Kazakhstan.
- Made final investment decision for the Gorgon Stage 2 Project in Australia.

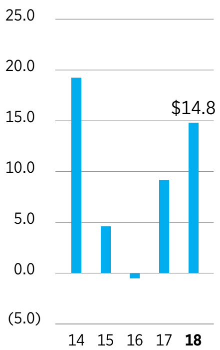
Downstream

Refining and marketing – First production commenced at the new hydrogen plant at the Richmond refinery in California.

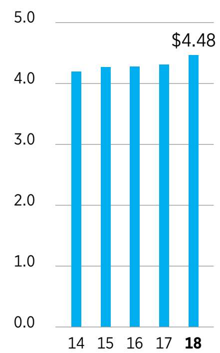
Additives – Reached a final investment decision for a lubricant additive blending and shipping plant in Ningbo, China.

Petrochemicals – Commissioned the ethane cracker at the U.S. Gulf Coast Petrochemicals Project in Texas and reached design capacity during second quarter.

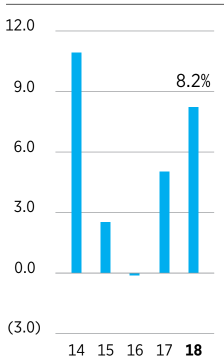
Net income (loss) attributable to Chevron Corporation
Billions of dollars



Annual cash dividends
Dollars per share



Return on capital employed
Percent



Financial summary

Year ended December 31

Millions of dollars	**2018**	2017	2016	2015	2014
Net income (loss) attributable to Chevron Corporation	**$ 14,824**	$ 9,195	$ (497)	$ 4,587	$ 19,241
Sales and other operating revenues	**158,902**	134,674	110,215	129,925	200,494
Cash dividends – common stock	**8,502**	8,132	8,032	7,992	7,928
Capital and exploratory expenditures	**20,106**	18,821	22,428	33,979	40,316
Cash flow from operating activities	**30,618**	20,338	12,690	19,456	31,475
Total cash and cash equivalents at December 31	**9,342**	4,813	6,988	11,022	12,785
Total assets at December 31	**253,863**	253,806	260,078	264,540	264,884
Total debt and capital lease obligations at December 31	**34,459**	38,763	46,126	38,549	27,784
Total liabilities at December 31	**98,221**	104,487	113,356	110,654	108,693
Chevron Corporation stockholders' equity at December 31	**154,554**	148,124	145,556	152,716	155,028
Share repurchases	**1,750**	–	–	–	5,000

Financial ratios*

Year ended December 31

	2018	2017	2016	2015	2014
Current ratio	**1.3**	1.0	0.9	1.3	1.3
Interest coverage ratio	**23.4**	10.7	(2.6)	9.9	87.2
Debt ratio	**18.2 %**	20.7 %	24.1 %	20.2 %	15.2 %
Net debt to capital ratio	**12.8 %**	18.2 %	20.4 %	14.2 %	8.0 %
Return on stockholders' equity	**9.8 %**	6.3 %	(0.3)%	3.0 %	12.7 %
Return on capital employed	**8.2 %**	5.0 %	(0.1)%	2.5 %	10.9 %
Return on total assets	**5.8 %**	3.6 %	(0.2)%	1.7 %	7.4 %
Cash dividends/net income (payout ratio)	**57.4 %**	88.4 %	(1,616.1)%	174.2 %	41.2 %
Cash dividends/cash from operations	**27.8 %**	40.0 %	63.3 %	41.1 %	25.2 %
Total stockholder return	**(9.8)%**	10.5 %	36.4 %	(16.0)%	(6.9)%

* Refer to page 55 for financial ratio definitions.

Capital employed

Year ended December 31

Millions of dollars		**2018**	2017	2016	2015	2014
Upstream	– United States	**$ 29,473**	$ 28,918	$ 25,855	$ 28,172	$ 29,808
	– International	**122,187**	126,943	130,900	125,043	113,009
	– Goodwill	**4,518**	4,531	4,581	4,588	4,593
	– Total	**156,178**	160,392	161,336	157,803	147,410
Downstream	– United States	**14,637**	13,543	12,353	12,946	12,509
	– International	**10,675**	11,201	10,758	10,802	11,210
	– Total	**25,312**	24,744	23,111	23,748	23,719
All Other		**8,611**	2,946	8,401	10,884	12,846
Total capital employed		**$ 190,101**	$ 188,082	$ 192,848	$ 192,435	$ 183,975

Employees

Year ended December 31

Number of employees	**2018**	2017	2016	2015	2014
Employees excluding service station employees	**45,047**	48,596	51,953	58,178	61,456
Service station employees	**3,591**	3,298	3,248	3,316	3,259
Total employed	**48,638**	51,894	55,201	61,494	64,715

Consolidated statement of income

Millions of dollars	2018	2017	2016	2015	2014
					Year ended December 31
Revenues and other income					
Total sales and other operating revenues[1]	**$ 158,902**	$ 134,674	$ 110,215	$ 129,925	$ 200,494
Income from equity affiliates	**6,327**	4,438	2,661	4,684	7,098
Other income	**1,110**	2,610	1,596	3,868	4,378
Total revenues and other income	**166,339**	141,722	114,472	138,477	211,970
Costs and other deductions					
Purchased crude oil and products	**94,578**	75,765	59,321	69,751	119,671
Operating expenses[2]	**20,544**	19,127	19,902	23,034	25,285
Selling, general and administrative expenses[2]	**3,838**	4,110	4,305	4,443	4,494
Exploration expenses	**1,210**	864	1,033	3,340	1,985
Depreciation, depletion and amortization	**19,419**	19,349	19,457	21,037	16,793
Taxes other than on income[1]	**4,867**	12,331	11,668	12,030	12,540
Interest and debt expense	**748**	307	201	–	–
Other components of net periodic benefit costs[2]	**560**	648	745	–	–
Total costs and other deductions	**145,764**	132,501	116,632	133,635	180,768
Income (loss) before income tax expense	**20,575**	9,221	(2,160)	4,842	31,202
Income tax expense (benefit)	**5,715**	(48)	(1,729)	132	11,892
Net income (loss)	**14,860**	9,269	(431)	4,710	19,310
Less: Net income attributable to noncontrolling interests	**36**	74	66	123	69
Net income (loss) attributable to Chevron Corporation	**$ 14,824**	$ 9,195	$ (497)	$ 4,587	$ 19,241

[1] 2017, 2016, 2015 and 2014 include excise, value-added and similar taxes of $7,189, $6,905, $7,359 and $8,186, respectively, collected on behalf of third parties. Beginning in 2018, these taxes are netted in *Taxes other than on income* in accordance with Accounting Standards Update (ASU) 2014-09.
[2] 2017 and 2016 adjusted to conform to ASU 2017-07.

Earnings by major operating area

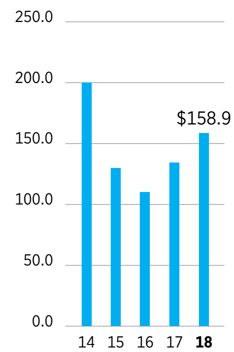
Millions of dollars		2018	2017	2016	2015	2014
						Year ended December 31
Upstream	– United States	**$ 3,278**	$ 3,640	$ (2,054)	$ (4,055)	$ 3,327
	– International	**10,038**	4,510	(483)	2,094	13,566
	– Total	**13,316**	8,150	(2,537)	(1,961)	16,893
Downstream	– United States	**2,103**	2,938	1,307	3,182	2,637
	– International	**1,695**	2,276	2,128	4,419	1,699
	– Total	**3,798**	5,214	3,435	7,601	4,336
All Other*		**(2,290)**	(4,169)	(1,395)	(1,053)	(1,988)
Net income (loss) attributable to Chevron Corporation		**$ 14,824**	$ 9,195	$ (497)	$ 4,587	$ 19,241

* *All Other* includes income from worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.

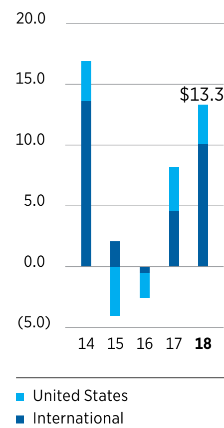
Common stock

	2018	2017	2016	2015	2014
					Year ended December 31
Number of shares outstanding at December 31 (Millions)	**1,888.7**	1,890.5	1,877.3	1,868.6	1,865.5
Weighted-average shares outstanding for the year (Millions)	**1,897.2**	1,882.4	1,872.3	1,867.2	1,882.9
Per-share data					
Net income (loss) attributable to Chevron Corporation					
– Basic	**$ 7.81**	$ 4.88	$ (0.27)	$ 2.46	$ 10.21
– Diluted	**7.74**	4.85	(0.27)	2.45	10.14
Cash dividends	**4.48**	4.32	4.29	4.28	4.21
Chevron Corporation stockholders' equity at December 31	**81.83**	78.35	77.53	81.73	83.10

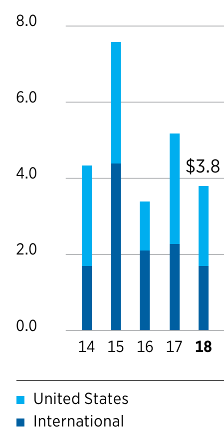
Total sales & other operating revenues
Billions of dollars



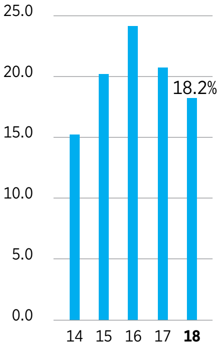
Worldwide Upstream earnings
Billions of dollars



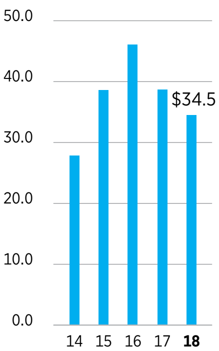
Worldwide Downstream earnings
Billions of dollars



Ratio of total debt to total debt-plus-Chevron Corporation stockholders' equity
Percent



Total debt at year-end
Billions of dollars



Consolidated balance sheet

At December 31

Millions of dollars	2018	2017	2016	2015	2014
Assets					
Cash and cash equivalents	**$ 9,342**	$ 4,813	$ 6,988	$ 11,022	$ 12,785
Time deposits	**950**	–	–	–	8
Marketable securities	**53**	9	13	310	422
Accounts and notes receivable, net	**15,050**	15,353	14,092	12,860	16,736
Inventories:					
Crude oil and petroleum products	**3,383**	3,142	2,720	3,535	3,854
Chemicals	**487**	476	455	490	467
Materials, supplies and other	**1,834**	1,967	2,244	2,309	2,184
Total inventories	**5,704**	5,585	5,419	6,334	6,505
Prepaid expenses and other current assets	**2,922**	2,800	3,107	3,904	4,705
Total current assets	**34,021**	28,560	29,619	34,430	41,161
Long-term receivables, net	**1,942**	2,849	2,485	2,412	2,817
Investments and advances	**35,546**	32,497	30,250	27,110	26,912
Properties, plant and equipment, at cost	**340,244**	344,485	336,077	340,277	327,289
Less: Accumulated depreciation, depletion and amortization	**171,037**	166,773	153,891	151,881	144,116
Properties, plant and equipment, net	**169,207**	177,712	182,186	188,396	183,173
Deferred charges and other assets	**6,766**	7,017	6,838	6,155	6,228
Goodwill	**4,518**	4,531	4,581	4,588	4,593
Assets held for sale	**1,863**	640	4,119	1,449	–
Total assets	**$ 253,863**	$ 253,806	$ 260,078	$ 264,540	$ 264,884
Liabilities and equity					
Short-term debt	**$ 5,726**	$ 5,192	$ 10,840	$ 4,927	$ 3,790
Accounts payable	**13,953**	14,565	13,986	13,516	19,000
Accrued liabilities	**4,927**	5,267	4,882	4,833	5,328
Federal and other taxes on income	**1,628**	1,600	1,050	1,073	1,761
Other taxes payable	**937**	1,113	1,027	1,118	1,233
Total current liabilities	**27,171**	27,737	31,785	25,467	31,112
Long-term debt*	**28,733**	33,571	35,286	33,622	23,994
Deferred credits and other noncurrent obligations	**19,742**	21,106	21,553	23,465	23,549
Noncurrent deferred income taxes	**15,921**	14,652	17,516	20,165	21,626
Noncurrent employee benefit plans	**6,654**	7,421	7,216	7,935	8,412
Total liabilities	**98,221**	104,487	113,356	110,654	108,693
Common stock	**1,832**	1,832	1,832	1,832	1,832
Capital in excess of par value	**17,112**	16,848	16,595	16,330	16,041
Retained earnings	**180,987**	174,106	173,046	181,578	184,987
Accumulated other comprehensive loss	**(3,544)**	(3,589)	(3,843)	(4,291)	(4,859)
Deferred compensation and benefit plan trust	**(240)**	(240)	(240)	(240)	(240)
Treasury stock, at cost	**(41,593)**	(40,833)	(41,834)	(42,493)	(42,733)
Total Chevron Corporation stockholders' equity	**154,554**	148,124	145,556	152,716	155,028
Noncontrolling interests	**1,088**	1,195	1,166	1,170	1,163
Total equity	**155,642**	149,319	146,722	153,886	156,191
Total liabilities and equity	**$ 253,863**	$ 253,806	$ 260,078	$ 264,540	$ 264,884

* Includes capital lease obligations of $127, $94, $93, $80 and $68 at December 31 for 2018, 2017, 2016, 2015 and 2014, respectively.

Segment assets

At December 31

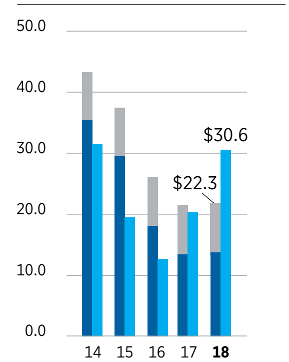
Millions of dollars	2018	2017	2016	2015	2014
Upstream*	**$ 200,973**	$ 204,913	$ 211,245	$ 213,001	$ 205,922
Downstream	**39,488**	40,636	38,080	36,386	40,789
Total segment assets	**$ 240,461**	$ 245,549	$ 249,325	$ 249,387	$ 246,711
All Other	**13,402**	8,257	10,753	15,153	18,173
Total assets	**$ 253,863**	$ 253,806	$ 260,078	$ 264,540	$ 264,884
* Includes goodwill associated with the acquisitions of Unocal Corporation in 2005 and Atlas Energy, Inc., in 2011:	**$ 4,518**	$ 4,531	$ 4,581	$ 4,588	$ 4,593

Consolidated statement of cash flows

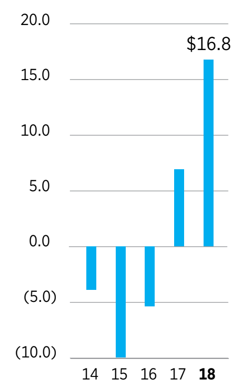
Millions of dollars	2018	2017	2016	2015	2014
					Year ended December 31
Operating activities					
Net income (loss)	**$ 14,860**	$ 9,269	$ (431)	$ 4,710	$ 19,310
Adjustments:					
Depreciation, depletion and amortization	**19,419**	19,349	19,457	21,037	16,793
Dry hole expense	**687**	198	489	2,309	875
Distributions less than income from equity affiliates[1]	**(3,580)**	(2,380)	(1,549)	(760)	(2,202)
Net before-tax gains on asset retirements and sales	**(619)**	(2,195)	(1,149)	(3,215)	(3,540)
Net foreign currency effects	**123**	131	186	(82)	(277)
Deferred income tax provision	**1,050**	(3,203)	(3,835)	(1,861)	1,572
Net decrease (increase) in operating working capital[2]	**(718)**	520	(327)	(1,979)	(540)
Decrease (increase) in long-term receivables	**418**	(368)	(131)	(59)	(9)
Net decrease (increase) in other deferred charges[2]	**–**	(254)	178	25	263
Cash contributions to employee pension plans	**(1,035)**	(980)	(870)	(868)	(392)
Other	**13**	251	672	199	(378)
Net cash provided by operating activities[1,2]	**30,618**	20,338	12,690	19,456	31,475
Investing activities					
Capital expenditures	**(13,792)**	(13,404)	(18,109)	(29,504)	(35,407)
Proceeds and deposits related to asset sales and returns of investment[1,2]	**2,392**	5,096	3,476	5,739	5,729
Net maturities of (investments in) time deposits	**(950)**	–	–	8	–
Net sales (purchases) of marketable securities	**(51)**	4	297	122	(148)
Net repayment (borrowing) of loans by equity affiliates	**111**	(16)	(2,034)	(217)	140
Net sales (purchases) of other short-term investments	**–**	–	–	44	(207)
Net cash used for investing activities[1,2]	**(12,290)**	(8,320)	(16,370)	(23,808)	(29,893)
Financing activities					
Net borrowing (repayments) of short-term obligations	**2,021**	(5,142)	2,130	(335)	3,431
Proceeds from issuances of long-term debt	**218**	3,991	6,924	11,091	4,000
Repayments of long-term debt and other financing obligations	**(6,741)**	(6,310)	(1,584)	(32)	(43)
Cash dividends – common stock	**(8,502)**	(8,132)	(8,032)	(7,992)	(7,928)
Distributions to noncontrolling interests	**(91)**	(78)	(63)	(128)	(47)
Net sales (purchases) of treasury shares	**(604)**	1,117	650	211	(4,412)
Net cash provided by (used for) financing activities	**(13,699)**	(14,554)	25	2,815	(4,999)
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**$ (91)**	65	(53)	(226)	(43)
Net change in cash and cash equivalents and restricted cash	**4,538**	(2,471)	(3,708)	(1,763)	(3,460)
Cash, cash equivalents and restricted cash at January 1	**$ 5,943**	8,414	12,122	12,785	16,245
Cash, cash equivalents and restricted cash at December 31	**$ 10,481**	$ 5,943	$ 8,414	$ 11,022	$ 12,785

[1] 2017 and 2016 adjusted to conform to ASU 2016-15.
[2] 2017 and 2016 adjusted to conform to ASU 2016-18.

Cash from operating activities compared with capital expenditures & dividends
Billions of dollars

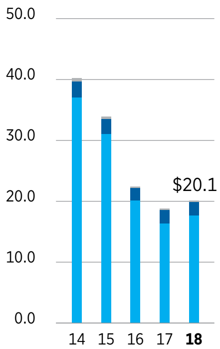


Free cash flow*
Billions of dollars



* The cash provided by operating activities less capital expenditures.

Capital & exploratory expenditures*
Billions of dollars



All Other
Downstream
Upstream

*Includes equity share in affiliates.

Capital and exploratory expenditures

(Includes equity share in affiliates)

Millions of dollars	2018	2017	2016	2015	2014
	Year ended December 31				
United States					
Exploration	**$ 802**	$ 745	$ 925	$ 1,680	$ 1,391
Production	**6,318**	4,398	3,787	5,874	7,354
Other Upstream	**8**	2	1	28	54
Refining	**1,097**	771	381	405	373
Marketing	**94**	48	55	76	66
Chemicals	**287**	771	1,011	1,354	1,025
Other Downstream	**104**	66	98	88	185
All Other	**243**	239	235	418	584
Total United States	**8,953**	7,040	6,493	9,923	11,032
International					
Exploration	**945**	528	527	1,339	2,131
Production	**9,550**	10,566	14,637	21,735	25,228
Other Upstream	**34**	149	239	461	957
Refining	**218**	175	115	131	309
Marketing	**139**	118	128	130	254
Chemicals	**75**	89	132	110	150
Other Downstream	**179**	152	152	142	228
All Other	**13**	4	5	8	27
Total International	**11,153**	11,781	15,935	24,056	29,284
Worldwide					
Exploration	**1,747**	1,273	1,452	3,019	3,522
Production	**15,868**	14,964	18,424	27,609	32,582
Other Upstream	**42**	151	240	489	1,011
Refining	**1,315**	946	496	536	682
Marketing	**233**	166	183	206	320
Chemicals	**362**	860	1,143	1,464	1,175
Other Downstream	**283**	218	250	230	413
All Other	**256**	243	240	426	611
Total Worldwide	**$ 20,106**	$ 18,821	$ 22,428	$ 33,979	$ 40,316
Memo: Equity share of affiliates' expenditures included above	**$ 5,716**	$ 4,743	$ 3,770	$ 3,397	$ 3,467

Exploration expenses[1]

Millions of dollars	2018	2017	2016	2015	2014
	Year ended December 31				
Geological and geophysical	**$ 140**	$ 184	$ 145	$ 372	$ 404
Unproductive wells drilled	**686**	199	488	2,309	875
Other[2]	**384**	481	400	659	706
Total exploration expenses	**$ 1,210**	$ 864	$ 1,033	$ 3,340	$ 1,985
Memo: United States	**$ 797**	$ 322	$ 416	$ 1,624	$ 586
International	**413**	542	617	1,716	1,399

[1] Consolidated companies only. Excludes amortization of undeveloped leaseholds.
[2] Includes amortization of unproved mineral interest, write-off of unproved mineral interest related to lease relinquishments, oil and gas lease rentals, and research and development costs.

Properties, plant and equipment

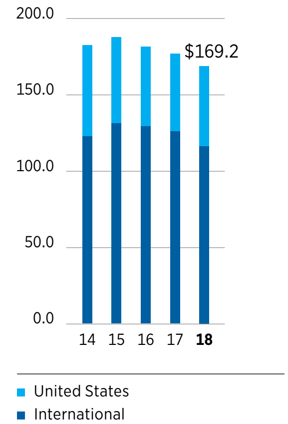
(Includes capital leases)

At December 31

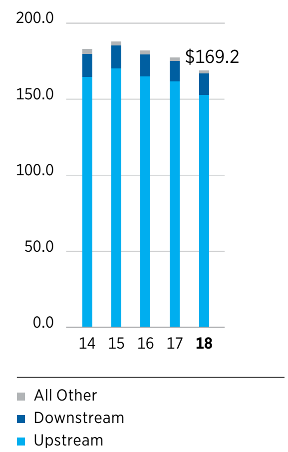
Millions of dollars	2018	2017	2016	2015	2014
Additions at cost					
Upstream[1]	**$ 11,299**	$ 12,929	$ 16,516	$ 26,579	$ 34,608
Downstream	**1,537**	1,213	903	1,061	1,118
All Other[2]	**230**	222	204	362	606
Total additions at cost	**13,066**	14,364	17,623	28,002	36,332
Depreciation, depletion and amortization expense[3]					
Upstream	**(18,054)**	(17,623)	(17,823)	(19,348)	(14,815)
Downstream	**(1,033)**	(1,035)	(1,288)	(1,233)	(1,282)
All Other[2]	**(332)**	(691)	(346)	(456)	(696)
Total depreciation, depletion and amortization expense	**(19,419)**	(19,349)	(19,457)	(21,037)	(16,793)
Net properties, plant and equipment at December 31					
Upstream[4]	**153,129**	161,913	165,212	170,584	164,790
Downstream	**13,861**	13,420	14,290	14,897	15,238
All Other[2]	**2,217**	2,379	2,684	2,915	3,145
Total net properties, plant and equipment at December 31	**$ 169,207**	$ 177,712	$ 182,186	$ 188,396	$ 183,173
Memo: Gross properties, plant and equipment	**$ 340,244**	$ 344,485	$ 336,077	$ 340,277	$ 327,289
Accumulated depreciation, depletion and amortization	**(171,037)**	(166,773)	(153,891)	(151,881)	(144,116)
Net properties, plant and equipment	**$ 169,207**	$ 177,712	$ 182,186	$ 188,396	$ 183,173
[4] Includes net investment in unproved oil and gas properties:	**$ 8,228**	$ 9,790	$ 12,249	$ 13,550	$ 14,490

[1] Net of exploratory well write-offs.
[2] *All Other* is primarily corporate administrative functions, insurance operations, real estate activities and technology companies.
[3] Depreciation expense includes accretion expense of $654, $668, $749, $715 and $882 in 2018, 2017, 2016, 2015 and 2014, respectively, and impairments of $735, $1,021, $3,186, $4,066 and $1,274 in 2018, 2017, 2016, 2015 and 2014, respectively.

Net properties, plant & equipment by geographic area
Billions of dollars



Net properties, plant & equipment by function
Billions of dollars



upstream

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

Photo: Chevron is one of the largest producers in the Permian Basin. The Permian is composed of several sub-basins, including the Midland and Delaware basins, which hold significant shale and tight resources.

highlights

Chevron's upstream business has operations in most of the world's key hydrocarbon basins and a portfolio that provides a foundation for future growth. Utilizing its project management expertise, innovative technology, experience in varied operating environments and strong partnership skills, upstream finds and develops resources that help meet global energy demand.

business strategies

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

- Sustaining world-class operational excellence.
- High-grading portfolio and effectively allocating capital.
- Delivering enterprise cash and earnings commitments while maintaining competitive margins.
- Leading the industry in the selection and execution of major capital projects.
- Replenishing resources through selective investments in technology, exploration and acquisitions.

upstream portfolio overview

industry conditions

Crude oil prices increased throughout the first three quarters of 2018 due to solid demand combined with OPEC production cuts. Late in the year, continued U.S. shale growth, along with increased production from key oil producing economies, led to excess supply conditions that resulted in a decrease in oil prices. In response, OPEC agreed to new production cuts in early December. The spot price for West Texas Intermediate (WTI) crude oil averaged $65 per barrel for full-year 2018, compared to $51 in 2017. The Brent price averaged $71 per barrel for full-year 2018, compared to $54 in 2017. The majority of the company's equity crude production is priced based on the Brent benchmark. WTI traded at a discount to Brent throughout 2018. Differentials to Brent have ranged between $3 and $10 in 2018 due to pipeline infrastructure constraints, which have restricted flows of inland crude to export outlets on the Gulf Coast. In response to the volatile crude price environment, the company continues to manage its cost structure and optimize its capital spending while still executing its business strategies.

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 for natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America. In the United States, prices at Henry Hub averaged $3.12 per thousand cubic feet (MCF) in 2018, compared to $2.97 per MCF in 2017. 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. In 2018, Chevron's international natural gas realizations averaged $6.29 per MCF, compared to $4.62 per MCF during 2017.

financial and operational highlights

In 2018, Chevron's upstream business had strong process and personal safety performance, achieving record low loss-of-containment incidents and outperforming on spill volume targets. Financial results improved substantially, with net income of $13.3 billion, compared to $8.2 billion in 2017. Record annual production of 2.93 million oil-equivalent barrels per day was more than 7 percent higher than net oil-equivalent production in 2017. Production increases from shale and tight properties, major capital projects, and base business were partially offset by entitlement effects, the impact of asset sales and normal field declines. Upstream capital and exploratory expenditures were $17.7 billion in 2018. Portfolio management activities resulted in proceeds of $1.0 billion, including the sale of assets primarily in the United States. In 2019, the upstream capital and exploratory budget is $17.3 billion. Approximately $10.4 billion of planned capital spending is forecasted to sustain currently producing assets, including $3.6 billion for the Permian Basin and $1.6 billion for other shale and tight rock investments. Approximately $5.1 billion is planned for major capital projects underway, including $4.3 billion of affiliate expenditures associated with the Future Growth and Wellhead Pressure Management Project (FGP/WPMP) at Tengizchevroil (TCO) in Kazakhstan. Global exploration funding is expected to be $1.3 billion. Remaining upstream spending is primarily related to early stage projects supporting potential future developments.

Upstream financial and operating highlights

(Includes equity share in affiliates)

Millions of dollars	2018	2017
Earnings	$ 13,316	$ 8,150
Net liquids production (Thousands of barrels per day)	1,782	1,723
Net natural gas production (Millions of cubic feet per day)	6,889	6,032
Net oil-equivalent production (Thousands of barrels per day)	2,930	2,728
Net proved reserves* (Millions of barrels of oil-equivalent)	12,053	11,665
Net unrisked resource base* (Billions of barrels of oil-equivalent)	68	69
Capital and exploratory expenditures	$ 17,657	$ 16,388

*For definitions of reserves and resources, refer to pages 54 and 55, respectively.

exploration and portfolio additions

Chevron's exploration focus areas comprise the deepwater U.S. Gulf of Mexico, offshore Western Australia, West Africa, and shale and tight resource plays throughout the United States, Canada and Argentina. The company's exploration activities have added approximately 12.8 billion barrels of potentially recoverable oil-equivalent resources since 2009. Notable exploratory drilling progressed in several areas around the globe during 2018, including the deepwater Gulf of Mexico, the Kurdistan Region of Iraq, and several shale and tight basins. In addition, the company made several important portfolio additions in 2018. Chevron successfully acquired new exploration acreage in multiple locations, including six deepwater blocks offshore Brazil in the pre-salt trend, 30 deepwater blocks in the U.S. waters of the Gulf of Mexico, and one deepwater block in Mexican waters of the Gulf of Mexico.

2018 accomplishments

- Exploration activities added 2.4 billion barrels of potentially recoverable oil-equivalent resources while making 11 discoveries worldwide and achieving an exploration drilling success rate of 61 percent.
- Added 1.3 million net exploration acres.
- Brazil – Awarded six deepwater blocks in the Campos and Santos basins.
- Mexico – License awarded for Block 22 in the deepwater of the Gulf of Mexico.
- United States – Made a significant crude oil discovery at the Ballymore prospect in the Gulf of Mexico and added 30 blocks (29 in lease sales, one through a swap).

2019 outlook

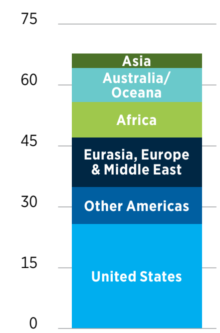
During 2019, the company plans to continue its selective and technology-driven exploration program by investing approximately $1.3 billion in exploration activities around the world. This planned exploration investment supports established exploration operations and also furthers the evaluation of recently acquired positions in Brazil, Mexico and various other locations. The 2019 drilling plans include 40 exploration and appraisal wells worldwide and the drilling or completion of nine impact wells (a well with a predrill unrisked resource potential of greater than 100 million barrels of oil-equivalent).

resources and proved reserves

The company's net unrisked resource base at year-end 2018 decreased slightly from year-end 2017 to 68 billion oil-equivalent barrels. Significant extensions and discoveries and technical revisions in the United States were offset by production and divestments. Included in the resource base are 12.1 billion barrels of net proved oil-equivalent reserves at year-end 2018.

The resources are diversified across geographic regions, with 38 percent located in the United States, 12 percent in Australia, 10 percent in Kazakhstan and 8 percent in Nigeria. The company's resource base is also diversified by type, with liquids representing about 60 percent and natural gas about 40 percent of the total. The company has about 164 trillion cubic feet of unrisked natural gas resources globally, with about half located in Australia and Asia, and is well positioned to supply anticipated growth in Asia-Pacific natural gas demand.

2018 net unrisked resources by region*
Billions of oil-equivalent barrels



* Refer to page 55 for definition of resources.

base business

Successful management of the base business is critical to maintaining the company's crude oil and natural gas production. Chevron drives a disciplined approach to managing the business through targeted investments and proven work processes to minimize decline and downtime and prevent process safety incidents. The company's assets have been operating reliably, with a production efficiency of 95 percent. Through a greater focus on data analytics, the company has been able to gain further insights into the performance of each business unit. Key focus areas for 2019 and beyond are pursuing further productivity and efficiency opportunities by utilizing cross-functional integrated operations centers, designing and deploying digital technology solutions, and advancing data analytics capability.

shale and tight resources

An area of focus for the company is the development of unconventional oil and gas resources located in shale and tight formations. The company has a significant shale and tight resource position, including legacy acreage in the Permian Basin in the United States, as well as newer positions in several other plays elsewhere in the United States, Argentina and Canada. Investment is focused on the liquids-rich shale and tight formations in the Permian Basin, the Vaca Muerta Shale in Argentina and the Duvernay Shale in Canada. In the Permian, the company has implemented a factory development strategy, which utilizes multiwell pads to drill a series of horizontal wells that are completed concurrently using hydraulic fracture stimulation. The company benefited from improved well performance in the Permian in 2018 and is forecasting continued growth in production from these resources over the next several years. Chevron also implemented a factory development strategy for the co-development of its Marcellus and Utica shale resources, which utilizes multiwell pads. Development activities continued in the Loma Campana area of the Vaca Muerta Shale, and a shale appraisal program commenced in 2018 in the El Trapial Field in Argentina. Development pace in Canada's Duvernay Shale is driven by well and execution performance. In the Liard Basin in Canada, the company is focused on identifying the areas with the most potential for development and bringing those resources to production safely and cost effectively. The company shares best practices across all of the shale and tight asset teams to ensure lessons learned are implemented across this asset class.

Shale and tight resources – key areas

Location	Basin or play	At December 31 Net acreage (Thousands of acres)
Argentina	Vaca Muerta	210
Canada	Duvernay	215
Canada	Liard/Horn River	290
United States	Permian (Delaware Basin)	1,200
United States	Permian (Midland Basin)	500
United States	Haynesville	71
United States	Marcellus	428
United States	Utica	462

major capital projects

Chevron continues to invest in major capital projects that play a significant role in developing resources into reserves and sustaining the company's production growth.

2018 accomplishments

- Australia – Achieved start-up of LNG Train 2 at the Wheatstone Project.
- Australia – Reached a final investment decision for Gorgon Stage 2.
- Kazakhstan – Advanced construction of the FGP/WPMP at TCO, including first module delivery and installation.
- United Kingdom – Commenced production at the Clair Ridge Project.
- United States – Achieved start-up of the Big Foot Project.
- United States – Achieved first oil from the Tahiti Vertical Expansion Project.
- United States – Commenced production at the Stampede Project.
- United States – Commenced front-end engineering design (FEED) for the Anchor project.

2019 outlook

- Australia – Achieve start-up of the carbon dioxide capture and injection process for Gorgon.
- Australia – Progress Jansz-Io Trunkline Compression Project, including initiation of FEED activities.
- Canada – Continue ramp-up of Hebron.
- Kazakhstan – Continue construction of the FGP/WPMP at TCO, including progressing the fabrication of pipe racks and process modules, and construction activities in the field.
- United Kingdom – Continue ramp-up of Clair Ridge.
- United States – Progress FEED activities for the Anchor project.
- United States – Continue ramp-up of Big Foot and Stampede in the Gulf of Mexico.

upstream

The projects in the table below are considered the most significant in the development portfolio and have commenced production or are in the design or construction phase. Each project has an estimated project cost of more than $500 million, Chevron share.

Major capital projects

Year of start-up[2]/location	Project	Ownership percentage	Operator	Facility design capacity[1] Liquids (MBPD)	Natural gas (MMCFPD)
2018					
United Kingdom	Clair Ridge	19.4	Other	120	100
United States	Big Foot	60.0	Chevron	75	25
	Stampede	25.0	Other	80	40
	Tahiti Vertical Expansion	58.0	Chevron	Maintain capacity	
2019–2022					
Australia	Gorgon Stage 2	47.3	Chevron	Maintain capacity	
Kazakhstan	TCO Future Growth Project (FGP)	50.0	Affiliate	260[3]	–
	TCO Wellhead Pressure Management Project (WPMP)	50.0	Affiliate	Maintain capacity	
United States	Mad Dog 2	15.6	Other	140	–
2023+					
Canada	Kitimat LNG	50.0	Chevron	–	1,600
Indonesia	IDD-Gendalo-Gehem	62.0	Chevron	30	920
United Kingdom	Captain Enhanced Oil Recovery Stage 2	85.0	Chevron	Maintain capacity	
United States	Anchor	61.3/55.0[4]	Chevron	75	28

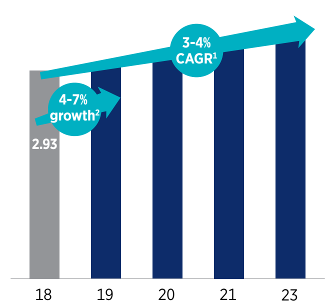
[1] MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day.
[2] Start-up timing for nonoperated projects per operator's estimate.
[3] Represents expected total daily production.
[4] Represents 61.3% interest in the northern unit area and 55% interest in the southern unit area.

production outlook

The company estimates that its average worldwide net oil-equivalent production in 2019 will grow 4 to 7 percent compared with 2018, assuming a Brent crude oil price of $60 per barrel and excluding the impact of anticipated 2019 asset sales. The company's production is expected to grow through the end of the decade as a result of value-driven investment in major capital projects and shale and tight properties and a sharp focus on mitigating base business declines. This growth is driven by the start-up and ramp-up of projects that have been under construction. These include the Gorgon and Wheatstone projects in Australia; the Stampede and Big Foot projects in the deepwater Gulf of Mexico; the Hebron Project in Canada; and the Clair Ridge Project in the United Kingdom. Shale and tight production, led by the Permian Basin and Canada, is anticipated to grow significantly. Infill wells, workovers, brownfield tie-backs and other optimization efforts are being utilized to mitigate base business decline rates.

This outlook for future production levels is subject to many factors and uncertainties, including, among other things, production quotas or other actions that might be imposed by OPEC; sanctions; price effects on entitlement volumes; changes in fiscal terms or restrictions on the scope of company operations; delays in the construction, start-up or ramp-up of projects; fluctuations in demand for natural gas; weather conditions; delays in completion of maintenance turnarounds; greater-than-expected declines from mature fields; potential asset divestments; or other disruptions to operations.

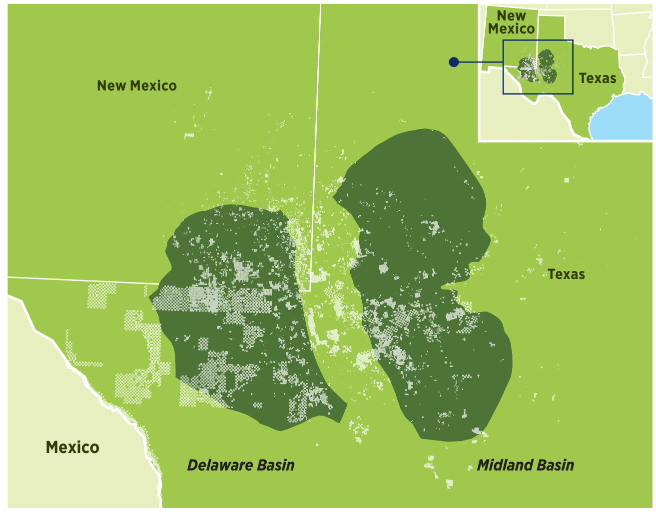
Projected net production at $60/bbl
MMBOED



[1] Includes the effect of asset sales in the public domain.
[2] Excludes the effect of asset sales.

United States

Chevron's portfolio in the United States encompasses a diverse group of assets primarily located in the midcontinent region, the Gulf of Mexico, California and the Appalachian Basin. The company was one of the largest liquids producers in the United States in 2018. Net daily oil-equivalent production averaged 791,000 barrels, representing 27 percent of the companywide total.



Chevron interest

Midcontinent

The company produces crude oil and natural gas in the midcontinent region of the United States, primarily in Colorado, New Mexico and Texas. In 2018, the company's net daily production in these areas averaged 198,000 barrels of crude oil, 651 million cubic feet of natural gas and 77,000 barrels of natural gas liquids (NGLs). In 2018, the company divested properties in New Mexico, Oklahoma and Texas. The company is pursuing opportunities to increase development efficiency across the region.

Permian Basin

The company's most significant holdings in the midcontinent region are in the Permian Basin located in West Texas and southeast New Mexico. Chevron has been active in the Permian since 1920 and has one of the largest net acreage positions in the basin, totaling approximately 2.2 million acres (8,903 sq km). More than 80 percent of its leases in the Permian Basin have either low or no royalty payments, providing a substantial competitive advantage. The Permian is composed of several sub-basins, including the Midland and Delaware basins, which hold significant shale and tight resources for development as well as resources that can be developed with conventional methods.

Chevron is one of the largest producers in the Permian Basin. In 2018, the company's net daily production in the basin averaged 159,000 barrels of crude oil, 501 million cubic feet of natural gas and 66,000 barrels of NGLs. Further refinement in reservoir characterization and enhanced use of data analytics has led to total net unrisked oil-equivalent resources estimated to exceed 16.2 billion barrels across Chevron's company-operated and nonoperated joint-venture portfolio.

In November 2018, Chevron joined forces with other leading Permian energy companies to form the Permian Strategic Partnership. This groundbreaking new industry coalition of 20 companies aims to improve the quality of life for Permian Basin families by partnering with local leaders to develop and implement strategic plans to foster strong schools, safer roads, quality health care, affordable housing and a trained workforce.

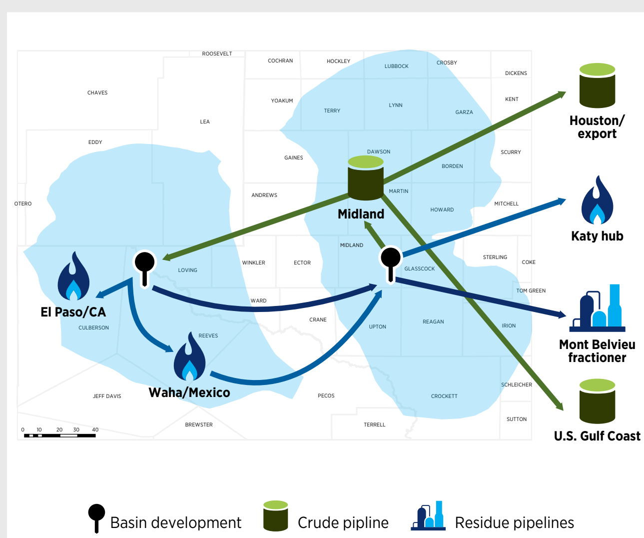
Permian takeaway position leads to enhanced value

Chevron is ensuring access to the best markets for crude, gas and NGLs

Chevron moves production via various pipelines and ships to reach multiple markets to capture the highest value for Permian production.

Commercial transactions are structured to support Chevron's long-term production in the Permian Basin. Agreement types include:

- Transport of crude from Midland market to U.S. Gulf Coast.
- Use of a crude export dock in the Houston Ship Channel to reach international markets.
- Committed NGL transportation and fractionation.
- Transport of natural gas to Permian Waha gas market center.
- Transport of natural gas from Waha to other gas market centers.



tight rock technology

Chevron continues to use technology to drive increased well performance

Chevron continues to advance proprietary technology and integrate emerging tight rock technologies and predictive analytics in support of exploration strategies, resource characterization and drilling and completion decisions, which are critical to optimizing the commercialization of our vast unconventional resources. Below are some examples of technology employed by Chevron:

- The company has developed and deployed an advanced regional stratigraphic framework that improves the understanding and prediction of the spatial distribution of mineralogic trends across the Permian Basin. These stratigraphic maps assist in high-grading future opportunities in the Permian. Similarly, Chevron developed a rock quality characterization workflow to support landing zone selection and multi zone development strategies in areas with limited data.
- The company developed proprietary modeling tools that employ machine learning and artificial intelligence to optimize well spacing and completion design, leading to lower development costs.
- The company utilizes a proprietary fracture stimulation optimization tool to increase effectiveness of the reservoir stimulation. This is coupled with surveillance technologies to understand completion effectiveness and drive improvements over time. The approach has lowered completion costs and increased recoverable reserves per well.
- The company utilizes proprietary drilling assembly technology that optimizes bit life and penetration rates through advanced modeling and analytical techniques.
- The company utilizes an integrated reservoir characterization and earth modeling workflow that incorporates detailed rock property data and a fine-scale reservoir/depositional framework into a high-resolution 3-D earth model used to assess optimal landing zone characteristics for unconventional reservoirs. This workflow has resulted in greater geologic accuracy, improved reservoir characterization, and reduced development costs through pad design and completion optimization.

Photo: Chevron continues to use technology to drive increased well performance.

Shale and tight resources

The company holds approximately 1.7 million net acres (6,880 sq km) of shale and tight resources in the Midland (approximately 500,000 net acres [2,023 sq km]) and Delaware (approximately 1.2 million net acres [4,856 sq km]) basins in the Permian. This acreage is positioned to deliver significant long-term growth for Chevron due to the presence of multiple stacked formations that enable production from several layers of rock in different geologic zones. Chevron has implemented a factory development strategy in the basin, which utilizes multiwell pads to drill a series of horizontal wells that are completed concurrently using hydraulic fracture stimulation. In addition to company-operated development, Chevron has a strong nonoperated joint-venture and royalty portfolio that drives enhanced value. Chevron is also applying data analytics and technology to drive improvements in well targets and performance. The company is forecasting double-digit production growth that is supported by increased average lateral length and a strong acreage position.

Chevron also holds approximately 71,000 net acres (287 sq km) in the Haynesville Shale in East Texas. In 2018, Chevron executed a lease retention program to maintain land position for a full development program in the future.

In addition, Chevron holds shale and tight resource opportunities in the Piceance Basin in northwestern Colorado.

Conventional resources

Chevron actively manages declines in its conventional oil and gas assets in the midcontinent region, including on its approximately 350,000 net acres (1,416 sq km) in the Central Basin Platform of the Permian Basin. The company is efficiently maintaining production of these conventional resources through well workovers, artificial-lift techniques, facility and equipment optimization, and enhanced recovery methods to maximize the value of these base business operations.

Gulf of Mexico

During 2018, net daily production in the Gulf of Mexico averaged 186,000 barrels of crude oil, 117 million cubic feet of natural gas and 13,000 barrels of NGLs. As of early 2019, Chevron has an interest in 218 leases in the Gulf of Mexico, 199 of which are located in water depths greater than 1,000 feet (305 m). At the end of 2018, the company was the second-largest leaseholder in the Gulf of Mexico.

Deep Water

Average net daily production in 2018 was 186,000 barrels of crude oil, 105 million cubic feet of natural gas and 13,000 barrels of NGLs, primarily from the Jack/St. Malo and Tahiti fields, the Perdido Regional Development, and the Caesar/Tonga, Tubular Bells, Blind Faith and Mad Dog fields.

Jack/St. Malo Chevron has a 50 percent interest in the Jack Field and a 51 percent interest in the St. Malo Field. Both fields are company operated and are located in the Walker Ridge area. The company has a 40.6 percent interest in the production host facility, which is designed to accommodate production from the Jack/St. Malo development and third-party tiebacks. Total daily production from the Jack and St. Malo fields in 2018 averaged 139,000 barrels of liquids (71,000 net) and 21 million cubic feet of natural gas (11 million net).

Additional development opportunities for the Jack and St. Malo fields progressed in 2018. Stage 2 of the development plan was completed with four planned wells on production by the end of 2018. Development drilling continued on Stage 3, with two of the three planned wells completed at the end of 2018. One additional well is planned to be drilled in 2019. Proved reserves have been recognized for these phases. Total daily production from the Jack/St. Malo development has ramped up to a daily rate of approximately 155,000 barrels of crude oil and 39 million cubic feet of natural gas. The Jack and St. Malo fields have an estimated remaining production life of 30 years, and total potentially recoverable oil-equivalent resources are estimated to exceed 500 million barrels. The company continues to study advanced drilling, completion and other production technologies that could be employed in future development phases, with the potential to increase recovery from these fields. The St. Malo Stage 4 waterflood project entered front-end engineering and design (FEED) in 2018, with the final investment decision expected in third quarter 2019. The project includes water injection at the St. Malo field, which would constitute Chevron's first waterflood project in the Wilcox trend. At the end of 2018, proved reserves had not been recognized for this project.

Tahiti In 2018, net daily production averaged 51,000 barrels of crude oil, 22 million cubic feet of natural gas and 3,000 barrels of NGLs at the 58 percent-owned and operated Tahiti Field. Infill drilling continued in 2018 with one new infill well being completed. The Tahiti Vertical Expansion Project is developing shallower reservoirs at the Tahiti asset and encompassing four new wells and associated subsea infrastructure. First oil was achieved from three wells in June 2018, and the fourth well is scheduled to come on line in second quarter 2019.

The Tahiti Field has an estimated remaining production life of at least 25 years.

Photo: First oil from the Tahiti Vertical Expansion Project was achieved in June 2018.

Mad Dog Chevron has a 15.6 percent nonoperated working interest in the Mad Dog Field. In 2018, net daily production averaged 8,000 barrels of liquids and 1 million cubic feet of natural gas.

The next development phase, the Mad Dog 2 Project, is planned to develop the southwestern extension of the Mad Dog Field. The development plan includes a new floating production platform with a design capacity of 140,000 barrels of crude oil per day. First oil is expected in 2021. The total potentially recoverable oil-equivalent resources for Mad Dog 2 are estimated to exceed 500 million barrels. Proved reserves have been recognized for the Mad Dog 2 Project.

Big Foot The development plan for the 60 percent-owned and operated Big Foot Project, located in the Walker Ridge area, includes a 15-slot drilling and production tension leg platform with water injection facilities. The facility has a design capacity of 75,000 barrels of crude oil and 25 million cubic feet of natural gas per day. First oil was achieved in November 2018 with ramp-up expected to continue during 2019. The field has an estimated production life of 35 years, and total potentially recoverable oil-equivalent resources are estimated to exceed 200 million barrels.

Photo: First oil was achieved from Big Foot in November 2018.

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

Photo: Production commenced at Stampede in January 2018 and continues to ramp up.

Anchor The Anchor Field is located in the Green Canyon area, approximately 140 miles (225 km) off the coast of Louisiana, in water depths of approximately 5,000 feet (1,524 m). Chevron has a 61.3 percent interest in the northern unit area and a 55 percent interest in the southern unit area. In 2018, the Chevron-operated Anchor Unit was expanded to include acreage in two additional blocks. FEED activities commenced in 2018. Stage 1 of the Anchor development consists of a seven-well subsea development and semi-submersible floating production unit. The planned facility has a design capacity of 75,000 barrels of crude oil and 28 million cubic feet of natural gas per day. The total potentially recoverable oil-equivalent resources for Anchor are estimated to exceed 450 million barrels. At the end of 2018, proved reserves had not been recognized for this project.

Ballymore Chevron is the operator of Ballymore, a 60 percent-owned field located in the Mississippi Canyon area, approximately 75 miles (120 km) off the coast of Louisiana and 3 miles (5 km) from Chevron's Blind Faith Platform, in water depth of 6,536 feet (1,992 m). In January 2018, the company announced a significant crude oil discovery. Appraisal activities are underway to evaluate the opportunity and identify a cost-effective development plan. The first appraisal well was completed in January 2019, and the results are being evaluated. At the end of 2018, proved reserves had not been recognized for this project.

Whale Chevron has a 40 percent nonoperated working interest in the Whale discovery in the Perdido area, located about 200 miles (322 km) southwest of Houston, Texas. An appraisal well and sidetrack were completed in March 2018. Results of the exploration and appraisal wells are being assessed in parallel to progressing cost-effective development options. At the end of 2018, proved reserves had not been recognized for this project.

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

Exploration During 2018 and early 2019, the company participated in five deepwater wells: three exploration and two appraisal wells. In early 2019, the company began drilling one exploration and one appraisal well.

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

Shelf

Average 2018 net daily production from the Gulf of Mexico shelf, where Chevron holds nonoperated interests in several fields, was 12 million cubic feet of natural gas.

utilizing technology to add value in the Gulf of Mexico

Chevron leverages technology and its strong Gulf of Mexico position to deliver increased production

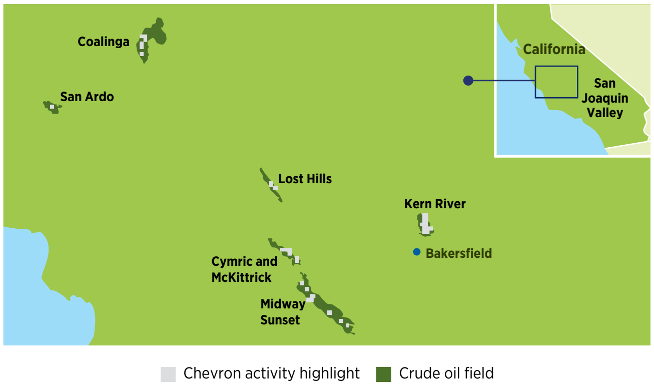
The company is utilizing its strong position in the Gulf of Mexico to optimize field development and performance, leveraging standard solutions and designs while deploying new technology and innovations.

- During 2018, Chevron successfully upgraded the Jack and St. Malo seafloor boosting pumps and increased production by approximately 20,000 barrels of crude oil per day.
- In December 2018, Chevron awarded contracts for the design, construction and operation of a new offshore drilling unit capable of handling pressures of 20,000 psi for use in the Anchor Field.
- Chevron integrates its advanced seismic imaging capabilities with machine learning and high-performance computing that enables reduced processing time and subsurface uncertainty, leading to improved business decisions in exploration and reservoir management.
- Ongoing efforts include standardization of subsea trees and topsides, advancement of cost-competitive tiebacks with shorter cycle times, and alignment of regulations and industry standards for drilling rigs capable of drilling in high-temperature, high-pressure environments.

Photo: In December 2018, Chevron awarded contracts for an ultra-deepwater drillship capable of handling pressures of 20,000 psi for use in the Anchor field.

California

In 2018, Chevron was one of the largest producers in California with net daily oil-equivalent production of 142,000 barrels, composed of 138,000 barrels of crude oil, 25 million cubic feet of natural gas and 400 barrels of NGLs.



Chevron has a 99 percent-owned and operated interest in leases covering most of the Kern River Field. In addition, the company operates leases in the Cymric Field (100 percent-owned), the McKittrick Field (98 percent-owned) and the Midway Sunset Field (94 percent-owned). Chevron also operates and holds interests in the San Ardo, Coalinga and Lost Hills fields. The company's expertise in steamflood operations has resulted in more than a 60 percent crude oil recovery rate at the Kern River Field. Chevron continues to leverage heat management capabilities in the recovery of these hydrocarbons, with emphasis on improved energy efficiency through new technology and processes. Chevron is progressing a project to supply solar power at the Lost Hills Field.

Chevron sold its nonoperated working interest in the Elk Hills Field in April 2018.

Photo: A pumpjack near a cogeneration power plant in Coalinga, California.

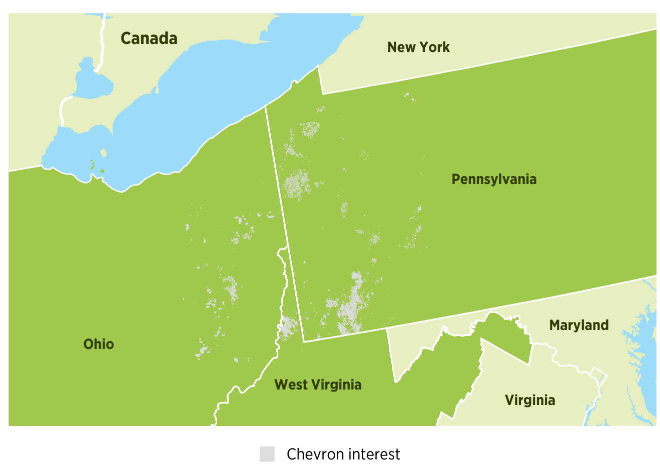
Appalachian Basin

The company is a significant leaseholder in the Marcellus Shale and the Utica Shale, primarily located in southwestern Pennsylvania, the West Virginia panhandle and eastern Ohio. Chevron has implemented a factory development strategy in the basin, which utilizes multiwell pads to drill horizontal wells that are completed using hydraulic fracture stimulation. This strategy enables future co-development of the Marcellus and Utica shales from the same pads in stacked play locations. In 2018, the company's net daily production in these areas averaged 240 million cubic feet of natural gas, 4,000 barrels of NGLs and 1,000 barrels of condensate.

Photo: Chevron has implemented a factory development strategy, which enables co-development of the Marcellus and Utica shales from the same pads.

Marcellus Shale The company holds approximately 428,000 net acres (1,732 sq km) in the Marcellus Shale. The company participated in 14 nonoperated wells during 2018. Development is planned to proceed at an optimal pace to achieve efficient factory execution that delivers enhanced well performance and cost effectiveness.

Utica Shale The company also holds a position in the Utica Shale, with approximately 462,000 net acres (1,870 sq km). Activity during 2018 included drilling an exploration well in the Utica formation to gather data necessary for potential future development.

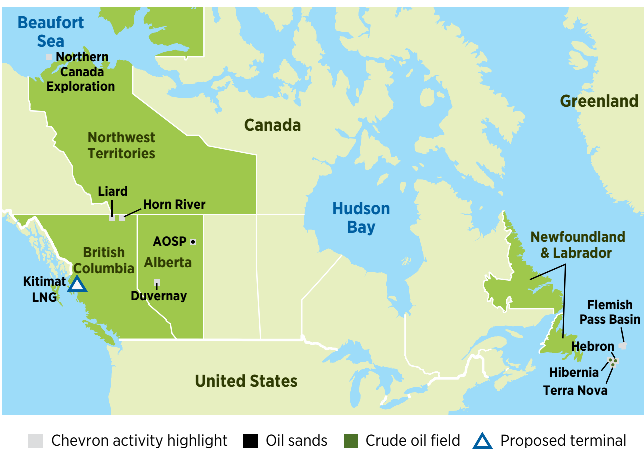


Other Americas

In Other Americas, the company is engaged in upstream activities in Argentina, Brazil, Canada, Colombia, Mexico, Suriname and Venezuela. Net daily oil-equivalent production of 209,000 barrels during 2018 in these countries represented 7 percent of the companywide total.

Canada

Chevron has interests in an oil sands project and shale acreage in the province of Alberta; exploration, development and production projects offshore the province of Newfoundland and Labrador in the Atlantic region; a liquefied natural gas (LNG) project and shale acreage in British Columbia; and discovered resource interests in the Beaufort Sea region of the Northwest Territories. Net daily production in 2018 from Canadian operations was 50,000 barrels of crude oil, 79 million cubic feet of natural gas and 53,000 barrels of synthetic oil from oil sands.



Atlantic Canada

Hibernia Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field. Chevron also has a 23.7 percent nonoperated working interest in the unitized Hibernia Southern Extension areas of the Hibernia Field that have been developed with a subsea tieback to the Hibernia Platform. Average net daily crude oil production in 2018 was 22,000 barrels.

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

Exploration Chevron holds a 50 percent-owned and operated interest in Flemish Pass Basin Block EL 1138, with 339,000 net acres (1,374 sq km). The company relinquished its interest in blocks EL 1125 and EL 1126 in 2018.

Western Canada

Athabasca Oil Sands Project (AOSP) The company holds a 20 percent nonoperated working interest in the AOSP near Fort McMurray, Alberta. Oil sands are mined from both the Muskeg River and the Jackpine mines. Bitumen is extracted from the oil sands and transported by pipeline to the Scotford Upgrader near Edmonton, Alberta, where it is upgraded into synthetic oil using hydroprocessing technology. Carbon dioxide emissions from the upgrader are reduced by the Quest carbon capture and storage facilities. In 2018, average net daily synthetic oil production was 53,000 barrels.

Duvernay Shale The company holds 215,000 net acres (870 sq km) in the Duvernay Shale in Alberta. Chevron has a 70 percent-owned and operated interest in most of the Duvernay acreage. Learnings from other Chevron-owned shale assets are being applied to continuously lower unit development costs while transitioning to factory development. Duvernay is poised for growth with access to premium Canadian condensate markets, and development pace will be driven by well and execution performance. A total of 122 wells have been tied into production facilities by early 2019. In 2018, net daily production averaged 9,000 barrels of crude oil and 54 million cubic feet of natural gas.

Photo: Execution of a development program in the Duvernay Shale in Alberta is underway.

Kitimat LNG Chevron holds a 50 percent-owned and operated interest in the proposed Kitimat LNG and Pacific Trail Pipeline projects and a 50 percent operated interest in 290,000 net acres (1,174 sq km) in the Liard and Horn River shale gas basins in British Columbia. The horizontal appraisal drilling program progressed during 2018. The Kitimat LNG Project is planned to include a two-train LNG facility and has a 10.0 million-metric-ton-per-year LNG export license. The total production capacity for the project is expected to be 1.6 billion cubic feet of natural gas per day. Major environmental and LNG export permits and First Nations benefits agreements are in place. Spending is being paced until LNG market conditions and reductions in project costs are sufficient to support the development of this project. At the end of 2018, proved reserves had not been recognized for this project.

Photo: Horizontal appraisal drilling progressed in the Liard Basin in 2018.

Mexico

The company operates and holds a 33.3 percent interest in Block 3 in the Perdido area of the Gulf of Mexico. The block covers 139,000 net acres (562 sq km). Seismic reprocessing activities continued in 2018.

In January 2018, a Chevron-led consortium was the successful bidder on an exploration license for Block 22 in the deepwater Cuenca Salina area of the Gulf of Mexico. Following license execution in May 2018, the company owns and operates a 37.5 percent interest in Block 22, which covers 267,000 net acres (1,081 sq km). A 3-D seismic licensing agreement was signed in August 2018, and data reprocessing has extended into 2019. An environmental baseline study was completed in October 2018.

Chevron activity highlight

Argentina

Chevron holds a 50 percent nonoperated interest in the Loma Campana and Narambuena concessions in the Vaca Muerta Shale covering 73,000 net acres (295 sq km). Chevron also holds an 85 percent-owned and operated interest in the El Trapial concession covering 94,000 net acres (380 sq km) with both conventional production and Vaca Muerta Shale potential. During 2018, Argentina net daily production averaged 20,000 barrels of crude oil and 24 million cubic feet of natural gas.

Loma Campana Nonoperated development activities continued in 2018 at the Loma Campana concession in the Vaca Muerta Shale, with three rigs on site at year-end. During 2018, 32 horizontal wells were drilled. During 2019, development activity is planned to increase to four rigs. This concession expires in 2048.

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

Exploration Evaluation of the nonoperated Narambuena Block continued in 2018, with appraisal activity planned for 2019. Chevron conducted an environmental review on the 90 percent-owned and operated Loma del Molle Norte Block, consisting of 43,000 net acres (174 sq km) adjacent to the El Trapial concession.

Chevron activity highlight

expanded use of real-time digital data

Sharing of technology enhances drilling performance in Chevron's worldwide shale assets

Chevron is leveraging real-time technology developed for and successfully used in deepwater operations to provide digital solutions for unconventional assets in Argentina, the Permian Basin, Marcellus and other locations around the world. Smart alarm systems and drilling and completion digital infrastructure are being utilized to optimize drilling and fracture performance and cost. These systems also enable remote steering of wells to optimize well placement and improve production outcomes from a central Drilling and Completion Decision Support Center in support of global operations.

Chevron developed and deployed the Digital Oil Field System, an integrated solution for managing the performance of assets, wells and facilities, to multiple assets across the portfolio. The system capabilities include real-time well and facility surveillance workflows, production condition monitoring, flowrate estimation, well diagnostics, and continuous automated validation between well models and field data.

Regular engagement sessions among the company's unconventional asset groups are held to support continuous process improvement, exchange best practices and review benchmark information.

Photo: The drilling program in Argentina is one of several areas across Chevron leveraging real-time technology to optimize drilling operations.

Brazil

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

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

Exploration In 2018, Chevron won six deepwater blocks in the prolific Brazil pre-salt trend within the Campos and Santos basins. In March 2018, Chevron was a successful bidder in four deepwater blocks, and now holds a 40 percent-owned and operated interest in the Santos basin S-M-764 Block and a 40 percent nonoperated interest in three Campos basin blocks, C-M-791, C-M-821 and C-M-823. Chevron was also a successful bidder in June 2018 with a 30 percent nonoperated interest in the Três Marias block and in September 2018 with a 50 percent nonoperated interest in the Saturno block, both in the Santos Basin. The six new blocks in the Brazil pre-salt cover 470,000 net acres (1,902 sq km). In December 2018, Chevron entered into an agreement to farm out 5 percent of its working interest in the Saturno block, resulting in a 45 percent nonoperated interest in this block. Following government approval of this agreement, Chevron's acreage in the Brazil pre-salt reduces to 460,000 net acres (1,860 sq km). Preparatory work for seismic data acquisition and environmental studies have been initiated.

Chevron activity highlight

Colombia

Chevron's activities in Colombia are focused on the production of natural gas from properties in the Caribbean Sea and adjacent coastal areas of the Guajira Peninsula. The company operates the offshore Chuchupa and onshore Ballena natural gas fields and receives 43 percent of the production for the remaining life of each field. Net daily production in 2018 averaged 82 million cubic feet of natural gas.

Chevron activity highlight

Suriname

Chevron holds a 33.3 percent and a 50 percent nonoperated working interest in Blocks 42 and 45 offshore Suriname, respectively. The deepwater exploration blocks cover a combined area of approximately 1.1 million net acres (4,622 sq km). Two exploratory wells were drilled in Blocks 42 and 45 in 2018, with additional exploratory drilling activity planned.

Venezuela

Chevron's production activities in Venezuela are located in western Venezuela and the Orinoco Belt. During 2018, net daily production averaged 42,000 barrels of crude oil and 9 million cubic feet of natural gas.

Petropiar Chevron holds a 30 percent interest in Petropiar, which operates the heavy oil Huyapari Field, formerly known as Hamaca, under an agreement expiring in 2033.

The project is located in the Orinoco Belt and includes processing and upgrading of extra heavy crude oil into lighter, higher-value synthetic oil. Net daily production averaged 26,000 barrels of liquids and 8 million cubic feet of natural gas during 2018. Sixty-four development wells were drilled in 2018.

Petroboscan The company holds a 39.2 percent interest in Petroboscan, which operates the onshore Boscan Field in western Venezuela under a contract expiring in 2026. During 2018, net daily production averaged 16,000 barrels of liquids and 1 million cubic feet of natural gas. Twenty-one development wells were drilled in 2018.

The company also holds a 25.2 percent interest in Petroindependiente, which operates the LL-652 Field in Lake Maracaibo under a contract expiring in 2026 and a 34 percent interest in Petroindependencia, which includes the Carabobo 3 heavy oil project located in three blocks in the Orinoco Belt. The Petroindependencia contract expires in 2035.

Loran Chevron operates and holds a 60 percent interest in Block 2 offshore Venezuela that is part of a cross-border unitized field including the Manatee Field in Trinidad and Tobago.

Greenland

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

Africa

In Africa, the company is engaged in upstream activities in Angola, Nigeria and the Republic of Congo. Net daily oil-equivalent production in this region was 450,000 barrels during 2018, representing 15 percent of the companywide total.

Angola

The company operates and holds a 39.2 percent interest in Block 0, a concession adjacent to the Cabinda coastline, and a 31 percent operated interest in a production-sharing contract (PSC) for deepwater Block 14, located west of Block 0. During 2018, net daily production averaged 107,000 barrels of liquids and 308 million cubic feet of natural gas.

The company has a 36.4 percent interest in Angola LNG Limited, which operates a 5.2 million-metric-ton-per-year LNG plant located in Soyo, Angola.

Block 0

Block 0 contains 21 fields that produced a net daily average of 81,000 barrels of liquids in 2018. The Block 0 concession extends through 2030.

Mafumeira Sul First liquified petroleum gas export began in January 2018. Ramp-up continued at the main production facility with total daily production in 2018 averaging 52,000 barrels of liquids (17,000 net) and 147 million cubic feet of natural gas (57 million net) exported to the Angola LNG plant. Six new wells were drilled in 2018.

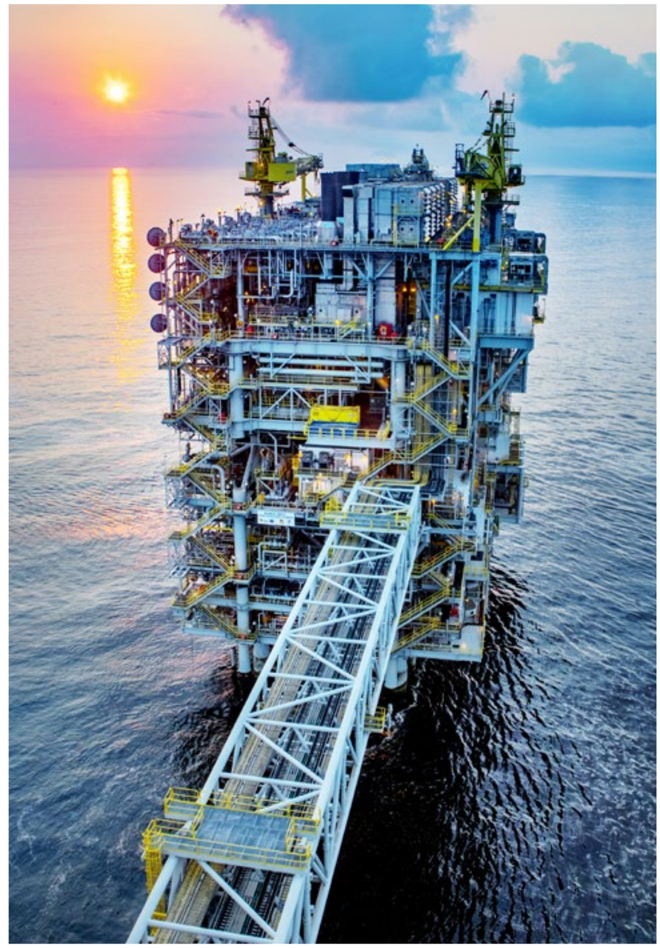


Photo: Mafumeira Sul ramp-up continued in 2018.

Block 14

In 2018, net daily production was 17,000 barrels of liquids from the Benguela Belize–Lobito Tomboco, Belize North, Benguela North, Tombua, Landana and Lianzi fields. Development and production rights for the various producing fields in Block 14 expire beginning in 2023, with the majority of the production held in leases that expire between 2027 and 2031.

Angola LNG

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

Photo: Well design optimization has helped reduce drilling days in Angola's Mafumeira field by more than 70 percent in five years.

base business success

Managing base business is key for mature assets

The company focuses on cost-effective management of base business assets. Well design optimization and improved efficiencies helped reduce average drilling days (drilling start to total depth) by more than 70 percent in five years in Mafumeira. The Block 0 base business drilling campaign continued in 2018 and preparation is underway for a new drilling campaign in Block 14 starting in 2019.

The company conducts regular asset performance reviews with subject matter experts to apply best practices and ensure continued asset optimization.

Angola–Republic of Congo Joint Development Area

Chevron is the operator of and holds a 31.3 percent interest in the Lianzi Unitization Zone, located in an area shared equally by Angola and the Republic of Congo. The Lianzi Project is reflected in the production totals in Angola (Block 14) and in the Republic of Congo.

Republic of Congo

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

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

Democratic Republic of the Congo

Chevron sold its 17.7 percent nonoperated working interest in a concession off the coast of the Democratic Republic of the Congo in April 2018.

Liberia

Chevron surrendered its 45 percent interest in Block LB-14 off the coast of Liberia in July 2018.

Morocco

The company surrendered its interest in the Cap Cantin Deep and Cap Walidia Deep acreage in September 2018.

Nigeria

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

Niger Delta

In 2018, net daily production from 28 fields in the Niger Delta averaged 66,000 barrels of crude oil, 217 million cubic feet of natural gas and 6,000 barrels of LPG.

Chevron completed the final well in its infill drilling program in the Niger Delta in first quarter 2019. Further infill drilling programs are beginning in 2019.

Chevron is continuing its efforts to monetize recoverable natural gas resources of approximately 17 trillion cubic feet in the Escravos area through a combination of domestic and export sales and use as fuel in company operations. The company is the operator of the Escravos Gas Plant (EGP) with a total processing capacity of 680 million cubic feet per day of natural gas and LPG and condensate export capacity of 58,000 barrels per day. The company is also the operator of the 33,000 barrel-per-day Escravos Gas to Liquids (EGTL) facility. In addition, the company holds a 36.7 percent interest in the West African Gas Pipeline Company Limited, which supplies Nigerian natural gas to customers in Benin, Ghana and Togo.

Sonam Field Development The 40 percent-owned and operated Sonam natural gas field is located in Oil Mining Lease (OML) 91. The Sonam Field Development Project is designed to process natural gas through the EGP facility and deliver it to the domestic gas market. Net daily production in 2018 averaged 10,000 barrels of liquids and 80 million cubic feet of natural gas per day. The drilling program, which included seven wells, was completed in early 2019.

Photo: Production from the Sonam Field development continued to ramp up in 2018.

Deep Water

In 2018, net daily production from the deep water Agbami and Usan fields averaged 128,000 barrels of crude oil and 16 million cubic feet of natural gas.

Agbami In 2018, net daily production from the Agbami Field averaged 108,000 barrels of crude oil and 12 million cubic feet of natural gas. The 67.3 percent-owned and operated field spans OML 127 and OML 128. The original Agbami development scope has been completed (Agbami 1, 2 and 3). Infill drilling continued in 2018 to further offset field decline, with additional infill drilling planned for 2019. The production licenses that contain the Agbami Field allows the company to produce until 2024.

Usan Chevron holds a 30 percent nonoperated working interest in the Usan Field in OML 138. Net daily production in 2018 averaged 20,000 barrels of crude oil and 4 million cubic feet of natural gas. The PSC expires in 2023.

Bonga SW/Aparo (BSWAP) The Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in OML 118 share a common geologic structure and are planned to be developed jointly. Chevron holds a 16.6 percent nonoperated working interest in the unitized area. The development plan involves subsea wells tied back to a floating production, storage and offloading vessel. Work continues to progress toward a final investment decision. At the end of 2018, no proved reserves were recognized for this project.

Exploration Chevron operates and holds a 55 percent interest in OML 140, which includes the Nsiko discoveries located 90 miles (145 km) off the coast of the western Niger Delta region in up to 8,000 feet (2,438 m) of water. A 3-D seismic acquisition program is planned for OML 140 and the adjacent OML 132 in 2019. Chevron's 30 percent nonoperated working interest in OML 138 includes the Usan Field and several satellite discoveries and a 27 percent interest in adjacent licenses OML 139 and OML 154. The company continues to work with the operator to evaluate development options for the multiple discoveries in the Usan area, including the Owowo Field which straddles OML 139 and Oil Prospecting License 223.

Asia

In Asia, upstream activities are located in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, the Kurdistan Region of Iraq, Myanmar, the Partitioned Zone between Saudi Arabia and Kuwait, the Philippines, Russia, and Thailand. In 2018, net daily oil-equivalent production of 970,000 barrels in this region represented 33 percent of the companywide total.

Azerbaijan

Chevron holds a 9.6 percent nonoperated interest in Azerbaijan International Operating Company (AIOC) and the crude oil production from the Azeri-Chirag-Gunashli (ACG) fields. AIOC operations are conducted under a PSC that expires in 2049. Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline affiliate, which transports the majority of ACG production from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities at Ceyhan, Turkey.

In 2018, average net daily production was 18,000 barrels of crude oil and 10 million cubic feet of natural gas. AIOC production is exported primarily via the BTC pipeline and the Western Route Export Pipeline (WREP), which is operated by AIOC. The 1,099-mile (1,768-km) BTC pipeline has the capacity to transport 1 million barrels per day. The WREP runs 515 miles (829 km) from Baku, Azerbaijan, to the terminal at Supsa, Georgia, on the Black Sea and transported approximately 76,000 barrels per day during 2018.

In 2018, Chevron announced its intent to market its share in AIOC and the BTC pipeline affiliate.

Kazakhstan

Chevron has a 50 percent interest in the Tengizchevroil (TCO) affiliate, which operates the Tengiz and Korolev fields, and an 18 percent nonoperated working interest in the Karachaganak Field. Net daily production in 2018 from TCO and Karachaganak was 315,500 barrels of liquids and 507 million cubic feet of natural gas.

Tengiz and Korolev

TCO is developing the Tengiz and Korolev crude oil fields in western Kazakhstan under a concession agreement that expires in 2033. Net daily production in 2018 averaged 269,000 barrels of crude oil, 387 million cubic feet of natural gas and 19,500 barrels of NGLs. All of TCO's crude oil production was exported through the Caspian Pipeline Consortium (CPC) pipeline.

Capacity and Reliability (CAR) Project The CAR Project was designed to reduce facility bottlenecks and increase plant capacity and reliability. The project was completed and put into operation in second quarter 2018.

well efficiency is a competitive advantage in Tengiz

Using the latest seismic imaging techniques improves well planning and results

At TCO, earth scientists are using Chevron's latest seismic imaging techniques to find the optimal targets for production wells several thousand feet below ground. The wells planned and drilled using Chevron's proprietary imaging capabilities have materially improved flowrates, enabling TCO to produce more at lower cost. TCO continues to use this competitive advantage as more wells are drilled and production grows with the FGP/WPMP expansion.

Photo: TCO uses the latest seismic imaging technology to increase production efficiency.

Future Growth and Wellhead Pressure Management Project (FGP/WPMP) The FGP/WPMP is being managed as a single integrated project. The FGP is designed to increase total daily production by about 260,000 barrels of crude oil and to expand the utilization of sour gas injection technology proven in existing operations to increase ultimate recovery from the reservoir. The WPMP is designed to maintain production levels in existing plants as reservoir pressure declines. First oil is planned for 2022. Proved reserves have been recognized for the FGP/WPMP.

The project advanced in 2018, including construction and operational readiness of the Cargo Transportation Route (CaTRo) facility. During 2018, CaTRo received 28 pre-assembled racks and 12 were successfully set on foundation. Additionally, a major milestone was achieved in September 2018, when the first modular unit of the processing plant arrived at the construction site in Kazakhstan. This module was successfully restacked by the end of the year, along with two gas turbine generator modules.

future growth and wellhead pressure management project

Project execution is dependent on close integration of several of Chevron's businesses

The recently completed Cargo Transportation Route facility is an integral part of this project, enabling fabricated equipment from international sites across the globe to be shipped to Tengiz.

Chevron's shipping organization provides transportation support for FGP's large modular equipment movements, and Chevron's power group provided functional expertise for the successful testing of the gas turbine modules and the integration of the new electrical power system equipment.

Photo: FGP/WPMP modular component departing the Korea fabrication yard.

Karachaganak

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

Kazakhstan/Russia

CPC The CPC operates a 935-mile (1,505-km) crude oil export pipeline from the Tengiz Field in Kazakhstan to tanker-loading facilities at Novorossiysk on the Russian coast of the Black Sea, providing a key export route for crude oil production from both TCO and Karachaganak. Chevron holds a 15 percent interest in the CPC. During 2018, the CPC pipeline transported an average of 1.3 million barrels of crude oil per day to Novorossiysk, composed of 1.2 million barrels per day from Kazakhstan and 147,000 barrels per day from Russia.

Photo: The CPC pipeline provides a key export route for crude oil production from both TCO and Karachaganak.

Bangladesh

Chevron operates and holds a 100 percent interest in two onshore PSCs in Bangladesh covering Block 12 (Bibiyana Field) and Blocks 13 and 14 (Jalalabad and Moulavi Bazar fields). The rights to produce from Jalalabad expire in 2030, from Moulavi Bazar in 2033 and from Bibiyana in 2034.

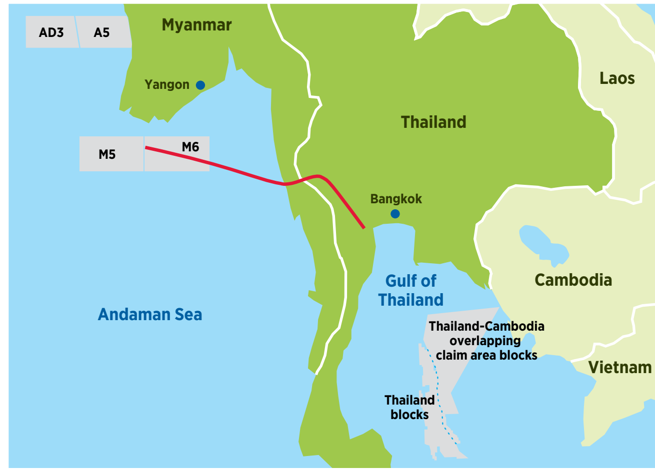
The company sells the natural gas production to the government under long-term sales agreements. In 2018, net daily production averaged 648 million cubic feet of natural gas and 4,000 barrels of condensate.

Chevron interest Natural gas field

Myanmar

Chevron has a 28.3 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana, Badamyar and Sein fields, within Blocks M5 and M6, in the Andaman Sea. The PSC expires in 2028 and covers 1.8 million net acres (7,320 sq km). The company also has a 28.3 percent nonoperated working interest in a pipeline company that transports natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. The remaining volumes are dedicated to the Myanmar market. Net daily natural gas production during 2018 averaged 98 million cubic feet.

Exploration Chevron holds a 55 percent-owned and operated interest in Blocks AD3 (1.4 million net acres, or 5,449 sq km) and A5 (1.4 million net acres, or 5,804 sq km). Seismic processing and interpretation continued in 2018.



Chevron interest Natural gas pipeline

Thailand

In the Gulf of Thailand, Chevron has operated and nonoperated working interests in multiple offshore blocks. Operated interests are in the Pattani Basin, with ownership ranging from 35 to 80 percent. Concessions for the producing areas in the Pattani Basin expire between 2022 and 2035. In the Malay Basin, Chevron holds a 16 percent nonoperated working interest in the Arthit Field. Concessions for the producing areas in the Malay Basin expire between 2036 and 2040. The company sells the natural gas production to the domestic market under long-term sales agreements. Net average daily production in 2018 was 66,000 barrels of crude oil and condensate and 1.0 billion cubic feet of natural gas.

Within the Pattani Basin, Chevron holds ownership ranging from 70 to 80 percent of the Erawan concession, which expires in 2022. Following the concession expiration, Chevron expects to transfer the Erawan operations to the Government of Thailand. Erawan concession's net average daily production in 2018 was 46,000 barrels of crude oil and condensate and 800 million cubic feet of natural gas.

Ubon The 35 percent-owned and operated Ubon Project in Block 12/27 completed FEED on a Central Processing Platform (CPP) with a floating, storage and offloading vessel for oil export in 2018. The project includes multiple wellhead platforms and infield pipelines to deliver production to the CPP. At the end of 2018, proved reserves had not been recognized for this project.

Exploration Chevron holds operated and nonoperated working interests ranging from 30 to 80 percent in the Thailand-Cambodia overlapping claims area. As of year-end 2018, these areas were inactive, pending resolution of border issues between Thailand and Cambodia.

China

Chevron operates the 49 percent-owned Chuandongbei Project, which is composed of several natural gas fields located onshore in the Sichuan Basin. This PSC expires in 2038.

The company also has three nonoperated PSCs. In the South China Sea, the company has a 32.7 percent working interest in offshore Block 16/19, with six crude oil fields located in the Pearl River Mouth Basin. In Bohai Bay, the company holds a 16.2 percent working interest in Block 11/19 and a 24.5 percent working interest in the Qinhuangdao (QHD) 32-6 Block. The PSCs for Block 11/19, QHD 32-6 Block and Block 16/19 expire in 2022, 2023 and 2028, respectively. In 2018, net average daily production from these PSCs was 16,000 barrels of crude oil.

Chuandongbei The Xuanhan Gas Plant has three gas processing trains with a design outlet capacity of 258 million cubic feet per day. Total daily production in 2018 averaged 183 million cubic feet of natural gas (84 million net).

Photo: The Chuandongbei Project in China produced an average of 183 million cubic feet per day of natural gas in 2018.

Philippines

Chevron holds a 45 percent nonoperated working interest in the offshore Malampaya Field. Net daily production during 2018 averaged 138 million cubic feet of natural gas and 3,000 barrels of condensate. The concession covers 92,000 net acres (374 sq km) and expires in 2024.

Indonesia

Chevron's operated interests in Indonesia include one onshore PSC on the island of Sumatra and three PSCs offshore eastern Kalimantan. Net daily production in 2018 from all producing areas in Indonesia averaged 113,000 barrels of liquids and 113 million cubic feet of natural gas.

Sumatra

Chevron holds a 100 percent-owned and operated interest in the Rokan PSC, which expires in 2021. Upon expiration of the PSC, Chevron expects to transfer Rokan operations to the Government of Indonesia. Net daily production averaged 104,000 barrels of crude oil and 22 million cubic feet of natural gas in 2018.

Kutei Basin

Chevron operates interests offshore eastern Kalimantan in three PSCs in the Kutei Basin: Makassar Strait (72 percent), Rapak (62 percent) and Ganal (62 percent). The PSCs for Makassar Strait, Rapak and Ganal expire in 2020, 2027 and 2028, respectively. Net daily production averaged 3,000 barrels of liquids and 38 million cubic feet of natural gas in 2018.

Chevron relinquished the East Kalimantan PSC in fourth quarter 2018.

Indonesia Deepwater Development There are two deepwater natural gas development projects in the Kutei Basin progressing under a single plan of development. Collectively, these projects are referred to as the Indonesia Deepwater Development. The company's owned and operated interest is 62 percent.

One of these projects, Bangka, includes a two-well subsea tieback to the West Seno Floating Production Unit, and is producing.

For the second project, Gendalo-Gehem, Chevron submitted a revised plan of development to the Government of Indonesia for approval in 2018. Current plans for marketing gas from the project include both domestic sale and LNG export after liquefaction at the state-owned Bontang LNG plant in East Kalimantan. The updated project has a planned design capacity of 920 million cubic feet of natural gas and 30,000 barrels of condensate per day. Chevron continues to work toward a final investment decision, subject to economic competitiveness, timing of government approvals, including extension of the associated PSCs, and securing new LNG sales contracts. This project is expected to monetize potentially recoverable natural gas resources of approximately 3 trillion cubic feet. At the end of 2018, proved reserves had not been recognized for this project.

Kurdistan Region of Iraq

The company holds a 50 percent contractor interest in the Sarta PSC and a 40 percent interest in the Qara Dagh PSC. The Sarta and Qara Dagh blocks cover an area of 90,000 net acres (363 sq km) and 170,000 net acres (689 sq km), respectively.

In July 2018, the company entered into an agreement with the Kurdistan Regional Government for the Qara Dagh block, which allows the company to continue evaluating exploration opportunities within the Qara Dagh block through October 2020.

The company has drilled two exploration wells and an appraisal well in the Sarta block and evaluation of these resource opportunities is ongoing. The Sarta PSC expires in 2047.

In February 2019, Chevron closed an agreement reducing the company's interest in both blocks and transferred operatorship of the Qara Dagh block. Chevron continues to operate the Sarta block through 2021 per a jointly developed transition plan.

Partitioned Zone

Chevron holds a concession agreement to operate the Kingdom of Saudi Arabia's 50 percent interest in the hydrocarbon resources in the onshore area of the Partitioned Zone between Saudi Arabia and Kuwait. Under the concession agreement, Chevron has the right to Saudi Arabia's 50 percent interest in the hydrocarbon resources. The concession expires in 2039.

Beginning in May 2015, production in the Partitioned Zone was shut in as a result of continued difficulties in securing work and equipment permits. As of early 2019, production remains shut in, and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait and the acquisition of necessary permits. Current work is focused on preservation activities and ensuring operational readiness for when resolution between the two governments is achieved.

Exploration Processing and interpretation of the 3-D seismic survey, which was acquired in 2016 and covers the entire onshore Partitioned Zone, has been completed. Work is underway to mature several exploration prospects.

Australia/Oceania

In Australia/Oceania, the company is engaged in upstream activities in Australia and New Zealand. Net daily oil-equivalent production of 426,000 barrels during 2018 in Australia represented 15 percent of the companywide total.

Australia

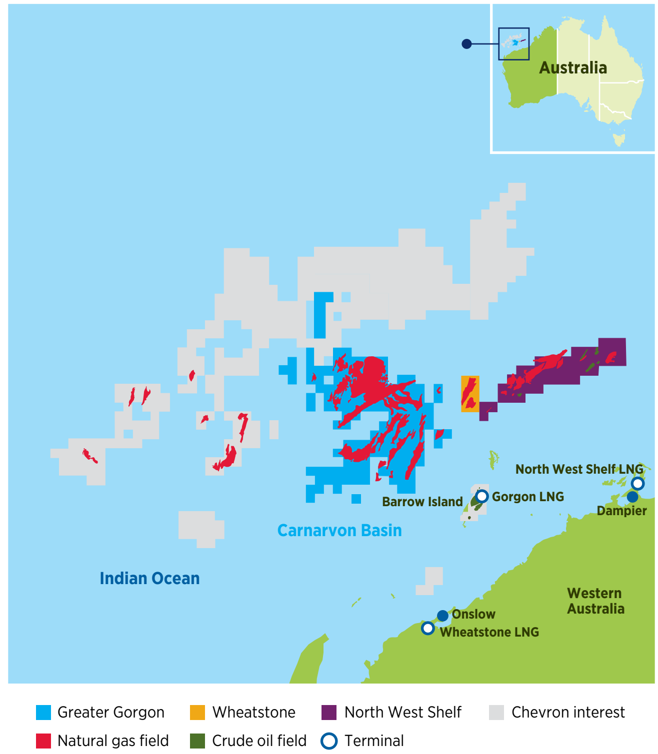
Chevron is Australia's largest producer of LNG with total installed liquefaction capacity of 24.5 million tons per year. The company is the operator of two major LNG facilities, Gorgon and Wheatstone, and has a nonoperated working interest in the North West Shelf Venture (NWS Venture). Chevron also has exploration acreage in the Carnarvon Basin and Browse Basin. The company holds net unrisked natural gas resources of approximately 50 trillion cubic feet in Australia. Net daily production in 2018 averaged 42,000 barrels of liquids and 2.3 billion cubic feet of natural gas, primarily from Gorgon, Wheatstone and the NWS Venture.

Gorgon Chevron holds a 47.3 percent interest in the Gorgon Project, which includes the development of the Gorgon and Jansz-Io fields. The project includes a three-train, 15.6 million-metric-ton-per-year LNG facility, a domestic gas plant, and a carbon dioxide capture and injection facility with first injection expected in 2019.

The facilities are located on Barrow Island. Total daily production from all three trains in 2018 averaged 18,000 barrels of condensate (8,500 net) and 2.6 billion cubic feet of natural gas (1.2 billion net). The project's estimated economic life exceeds 40 years.

In April 2018, the company reached a final investment decision for Gorgon Stage 2, which includes 11 new wells in the Gorgon and Jansz-Io fields and additional subsea infrastructure to sustain long-term supply to Gorgon. Drilling of the new wells is expected to begin in second quarter 2019.

The Jansz-Io Trunkline Compression Project is planned to provide access to compression for the Jansz-Io field, as well as future backfill fields connected to the Jansz trunkline. The project supports maintaining gas supply to the Gorgon LNG plant and maximizing the recovery of fields accessing the Jansz trunkline. The project is anticipated to enter FEED in second quarter 2019.



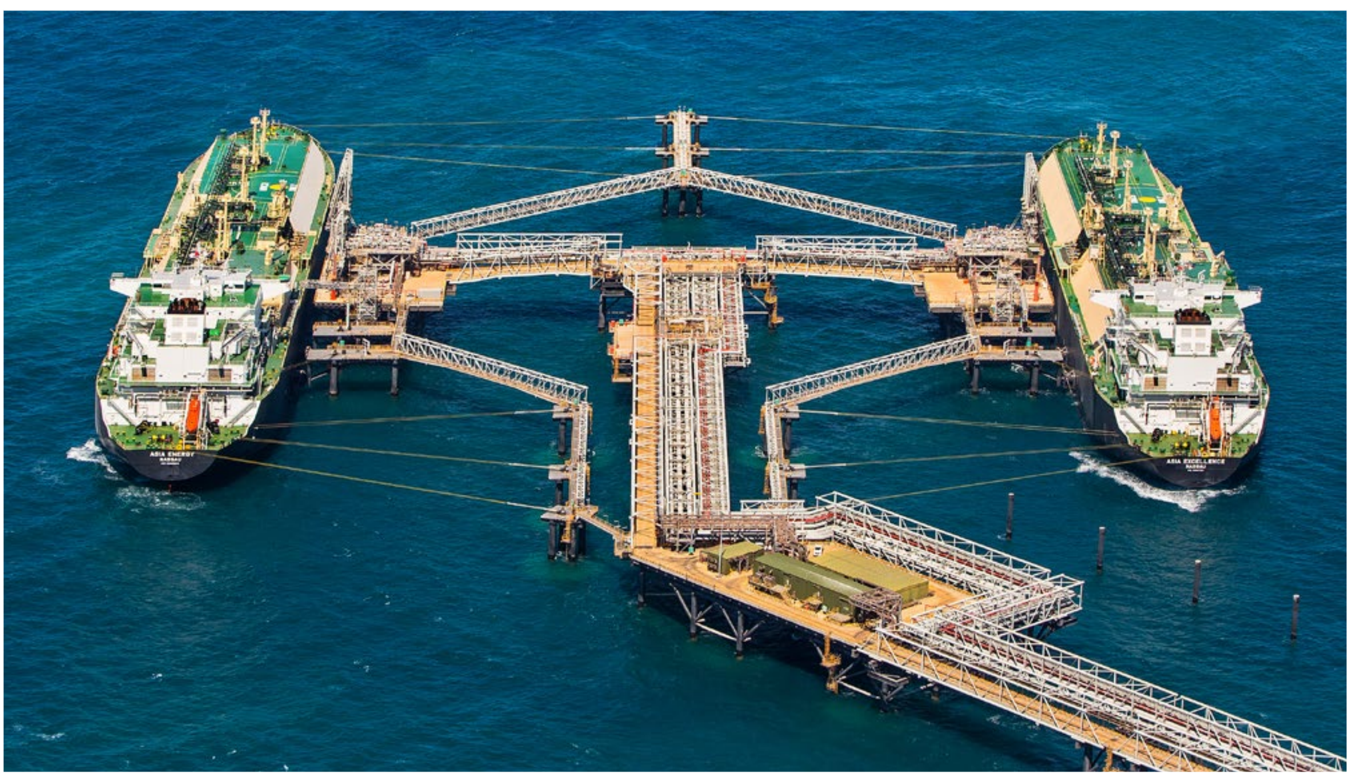


Photo: Two LNG ships load cargo at the Gorgon jetty at Barrow Island.

Wheatstone Chevron holds an 80.2 percent interest in the offshore licenses and a 64.1 percent interest in the LNG facilities associated with the Wheatstone Project. The project includes the development of the Wheatstone and Iago fields, a two-train, 8.9 million-metric-ton-per-year LNG facility, and a domestic gas plant. The facilities are located at Ashburton North on the coast of Western Australia. The total production capacity for the Wheatstone and Iago fields and nearby third-party fields is expected to be approximately 1.6 billion cubic feet of natural gas and 30,000 barrels of condensate per day. The project's estimated economic life exceeds 30 years.

LNG Train 2 start-up and first cargo shipment were achieved in June 2018. Total daily production averaged 16,000 barrels of condensate (12,800 net) and 801 million cubic feet of natural gas (642 million net) in 2018.

Photo: Start-up of Wheatstone's second train was achieved in June 2018.

NWS Venture Chevron has a 16.7 percent nonoperated working interest in the NWS Venture in Western Australia. The joint venture operates offshore producing fields and extensive onshore facilities that include five LNG trains and a domestic gas plant.

Net daily production in 2018 averaged 16,000 barrels of crude oil and condensate, 444 million cubic feet of natural gas, and 2,000 barrels of LPG.

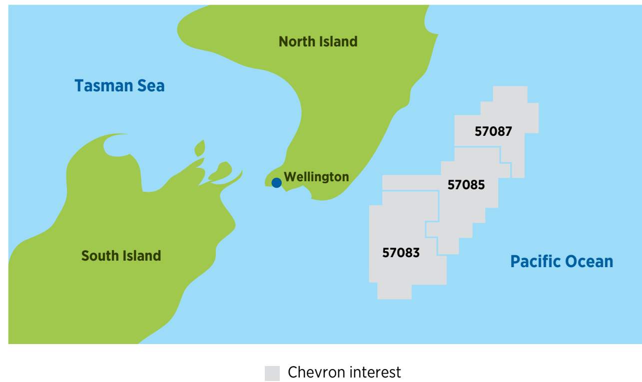
Barrow Island Chevron holds a 57.1 percent operating working interest in crude oil production operations at Barrow Island.

Exploration The company holds 50 percent-owned and operated interests in four exploration permits in the northern Carnarvon Basin, which cover more than 2.9 million net acres (11,736 sq km). Chevron continued to evaluate exploration potential in the basin during 2018. The company also holds nonoperated working interests ranging from 24.8 to 50 percent in three blocks in the Browse Basin. Relinquishment of the offshore blocks in the Bight Basin is pending Australian government approval.

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

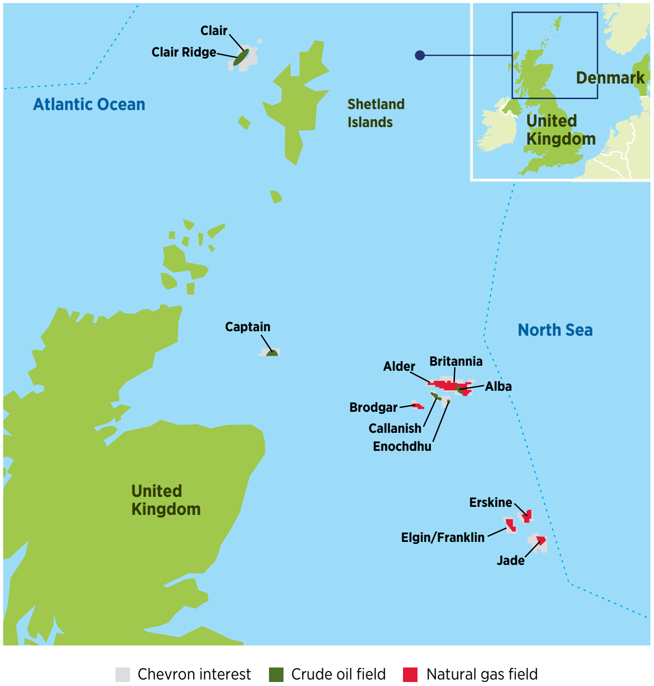
New Zealand

Chevron holds a 50 percent interest and operates three exploration permits, 57083, 57085 and 57087, in the offshore Pegasus and East Coast basins. These deepwater permits cover 3.1 million net acres (12,545 sq km) and are located approximately 99 miles (160 km) east of Wellington. Seismic processing and interpretation continued in 2018 in preparation for a decision regarding entering the exploration Stage 2 in 2019.



Europe

In Europe, the company is engaged in upstream activities in Denmark and the United Kingdom. Net daily oil-equivalent production in this region of 84,000 barrels during 2018 represented 3 percent of the companywide total.



United Kingdom

Chevron has working interests in 11 offshore producing fields, including four operated fields (Alba, 23.4 percent; Alder, 73.7 percent; Captain, 85 percent; and Erskine, 50 percent) and seven nonoperated fields (Britannia, 32.4 percent; Brodgar, 6.3 percent; Callanish, 16.5 percent; Clair, 19.4 percent; Elgin/Franklin, 3.9 percent; Enochdhu, 50 percent; and Jade, 19.9 percent). In 2018, Chevron announced its intent to market its Central North Sea assets, including Captain.

Net daily production in 2018 averaged 43,000 barrels of liquids and 133 million cubic feet of natural gas.

Photo: First production for the Clair Ridge Project was achieved in November 2018.

Clair Ridge The Clair Ridge Project, located 47 miles (75 km) west of the Shetland Islands, is the second development phase of the Clair Field. Chevron holds a 19.4 percent nonoperated working interest in the project. The design capacity of the project is 120,000 barrels of crude oil and 100 million cubic feet of natural gas per day. First production was achieved in November 2018. The project is estimated to provide incremental potentially recoverable oil-equivalent resources in excess of 600 million barrels. The Clair Field has an estimated production life extending until 2050.

Captain EOR The Captain Enhanced Oil Recovery (EOR) Project is the next development phase of the Captain Field and is designed to increase field recovery by injecting a polymer/water mixture into the Captain reservoir. Stage 1 of the project is an expansion of the existing polymer injection system on the wellhead production platform that includes six new polymer injection wells and modifications to platform facilities. Proved reserves have been recognized for Stage 1. Also, during 2018, FEED activities continued to progress on Captain EOR Stage 2, which involves subsea expansion of the technology. At the end of 2018, proved reserves had not been recognized for Stage 2 of the project.

Rosebank In January 2019, the company sold its 40 percent operated working interest in the Rosebank field.

Denmark

Chevron signed an agreement for the sale of its 12 percent nonoperated working interest in the Danish Underground Consortium in September 2018. The sale is expected to close in 2019, pending regulatory approval. Average net daily production in 2018 was 12,000 barrels of crude oil and 45 million cubic feet of natural gas.

Norway

In November 2018, the company divested its 20 percent nonoperated working interest in exploration Block PL 859, located in the Barents Sea.

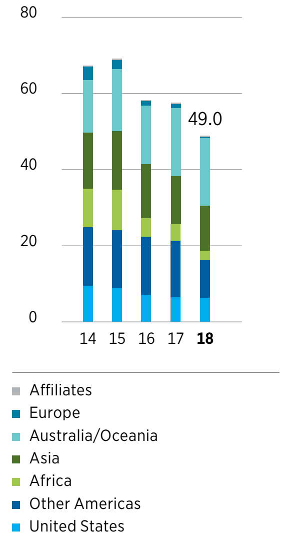
upstream operating data

Oil and gas acreage[1,2]

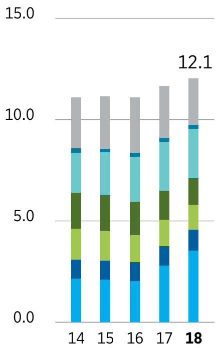
						At December 31
	Gross acres					Net acres
Thousands of acres	**2018**	**2018**	2017	2016	2015	2014
Consolidated Companies						
Total United States	**7,733**	**6,336**	6,381	7,121	8,885	9,444
Other Americas						
Argentina	**305**	**210**	167	240	240	240
Brazil	**1,423**	**578**	105	105	104	105
Canada	**10,268**	**7,459**	13,201	13,218	12,913	13,204
Colombia	**200**	**87**	87	87	87	87
Greenland	**–**	**–**	–	350	350	350
Mexico	**1,128**	**406**	139	–	–	–
Suriname	**2,793**	**1,142**	1,142	1,142	1,396	1,396
Trinidad and Tobago	**–**	**–**	–	84	84	84
Venezuela	**74**	**58**	58	58	58	58
Total Other Americas	**16,191**	**9,940**	14,899	15,284	15,232	15,524
Africa						
Angola	**2,257**	**787**	787	802	802	802
Democratic Republic of the Congo	**–**	**–**	44	44	44	44
Liberia	**–**	**–**	260	260	819	819
Mauritania	**–**	**–**	–	–	1,985	–
Morocco	**–**	**–**	1,708	2,112	5,415	5,415
Nigeria	**3,581**	**1,552**	1,552	1,552	1,552	2,194
Republic of Congo	**203**	**53**	56	56	56	63
Sierra Leone	**–**	**–**	–	–	–	762
Total Africa	**6,041**	**2,392**	4,407	4,826	10,673	10,099
Asia						
Azerbaijan	**108**	**10**	10	12	12	12
Bangladesh	**186**	**186**	186	186	186	186
China	**343**	**133**	134	134	134	1,565
Indonesia	**2,423**	**2,127**	3,202	4,683	5,853	5,853
Kazakhstan	**67**	**12**	12	12	12	12
Kurdistan Region of Iraq	**325**	**260**	90	279	279	355
Myanmar	**11,513**	**4,605**	4,407	4,407	4,407	1,826
Partitioned Zone	**1,361**	**681**	681	681	681	681
Philippines	**206**	**93**	93	93	93	93
Thailand	**9,506**	**3,775**	3,797	3,797	3,797	3,843
Vietnam	**–**	**–**	–	–	–	339
Total Asia	**26,038**	**11,882**	12,612	14,284	15,454	14,765
Australia/Oceania						
Australia	**21,426**	**14,719**	14,881	12,343	13,061	13,875
New Zealand	**6,240**	**3,120**	3,120	3,120	3,216	–
Total Australia/Oceania	**27,666**	**17,839**	18,001	15,463	16,277	13,875
Europe						
Denmark	**406**	**49**	49	49	49	49
Norway	**–**	**–**	168	168	–	520
Poland	**–**	**–**	–	–	–	499
Romania	**–**	**–**	670	670	2,239	2,239
United Kingdom	**670**	**304**	170	188	210	210
Total Europe	**1,076**	**353**	1,057	1,075	2,498	3,517
Total Consolidated Companies	**84,745**	**48,742**	57,357	58,053	69,019	67,224
Equity Share in Affiliates						
Kazakhstan	**380**	**190**	190	190	190	190
Venezuela	**424**	**146**	146	143	145	145
Total Equity Share in Affiliates	**804**	**336**	336	333	335	335
Total Worldwide	**85,549**	**49,078**	57,693	58,386	69,354	67,559

[1] Table does not include mining acreage associated with synthetic oil production in Canada.
[2] Net acreage includes wholly owned interests and the sum of the company's fractional interests in gross acreage.

Oil and gas acreage
Millions of net acres



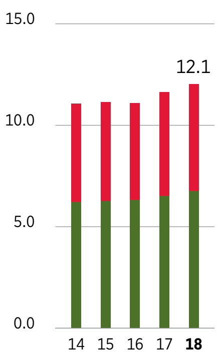
Net proved reserves
Billions of BOE*



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

*BOE (barrels of oil-equivalent)

Net proved reserves liquids & natural gas
Billions of BOE



- Natural gas
- Liquids

Net proved reserves – liquids[1,2]

At December 31

Millions of barrels	2018	2017	2016	2015	2014
Consolidated Companies					
United States	**2,402**	1,916	1,412	1,386	1,432
Other Americas	**908**	840	827	833	772
Africa	**776**	839	876	957	1,021
Asia	**579**	631	720	790	752
Australia/Oceania	**161**	159	158	153	142
Europe	**149**	145	138	143	166
Total Consolidated Companies	**4,975**	4,530	4,131	4,262	4,285
Equity Share in Affiliates					
TCO	**1,605**	1,749	1,909	1,676	1,615
Other	**210**	263	288	324	349
Total Equity Share in Affiliates	**1,815**	2,012	2,197	2,000	1,964
Total Worldwide	**6,790**	6,542	6,328	6,262	6,249

[1] Refer to page 54 for a definition of net proved reserves. For additional discussion of the company's proved reserves, refer to the company's *2018 Annual Report on Form 10-K*.
[2] Includes crude oil, condensate, NGLs and synthetic oil.

Net proved reserves – natural gas*

At December 31

Billions of cubic feet	2018	2017	2016	2015	2014
Consolidated Companies					
United States	**6,709**	5,180	3,676	4,242	4,174
Other Americas	**863**	795	647	714	1,123
Africa	**2,815**	2,906	2,827	2,937	2,968
Asia	**4,310**	4,773	5,533	5,956	6,266
Australia/Oceania	**13,731**	13,559	12,515	11,873	10,941
Europe	**305**	301	234	224	235
Total Consolidated Companies	**28,733**	27,514	25,432	25,946	25,707
Equity Share in Affiliates					
TCO	**1,934**	2,183	2,242	2,268	2,177
Other	**909**	1,039	1,086	1,223	1,232
Total Equity Share in Affiliates	**2,843**	3,222	3,328	3,491	3,409
Total Worldwide	**31,576**	30,736	28,760	29,437	29,116

*Refer to page 54 for a definition of net proved reserves. For additional discussion of the company's proved reserves, refer to the company's *2018 Annual Report on Form 10-K*.

upstream operating data

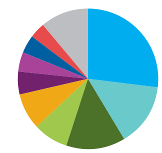
Net oil-equivalent production

Thousands of barrels per day — Year ended December 31

	2018	2017	2016	2015	2014
Consolidated Companies					
Total United States	**791**	681	691	720	664
Other Americas					
Argentina	**24**	23	26	27	25
Brazil	**11**	13	16	18	21
Canada	**116**	98	92	69	69
Colombia	**14**	16	21	27	31
Trinidad and Tobago	**–**	5	12	19	19
Total Other Americas	**165**	155	167	160	165
Africa					
Angola	**108**	112	114	119	121
Chad	**–**	–	–	–	8
Democratic Republic of the Congo	**1**	2	2	3	3
Nigeria	**239**	250	235	270	286
Republic of Congo	**52**	38	25	20	16
Total Africa	**400**	402	376	412	434
Asia					
Azerbaijan	**20**	25	32	34	28
Bangladesh	**112**	111	114	123	109
China	**29**	30	27	24	16
Indonesia	**132**	164	203	207	185
Kazakhstan	**46**	55	62	56	53
Myanmar	**16**	19	21	20	16
Partitioned Zone	**–**	–	–	28	81
Philippines	**26**	25	26	23	23
Thailand	**236**	241	245	238	238
Total Asia	**617**	670	730	753	749
Australia/Oceania					
Australia	**426**	256	124	94	97
Total Australia/Oceania	**426**	256	124	94	97
Europe					
Denmark	**19**	23	22	24	25
Netherlands	**–**	–	–	–	7
Norway	**–**	–	–	–	1
United Kingdom	**65**	75	64	59	47
Total Europe	**84**	98	86	83	80
Total Consolidated Companies	**2,483**	2,262	2,174	2,222	2,189
Equity Share in Affiliates					
TCO	**353**	360	348	336	314
Venezuela	**44**	55	59	64	63
Angola LNG	**50**	51	13	–	5
Total Equity Share in Affiliates	**447**	466	420	400	382
Total Worldwide	**2,930**	2,728	2,594	2,622	2,571

2018 net oil-equivalent production by country*

Percentage

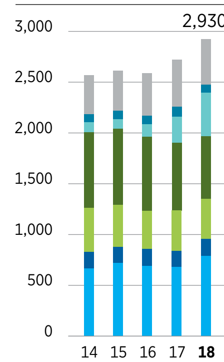


United States	27.0%
Australia	14.5%
Kazakhstan	13.6%
Nigeria	8.2%
Thailand	8.1%
Angola	5.4%
Indonesia	4.5%
Canada	4.0%
Bangladesh	3.8%
Other	10.9%

* Includes equity share in affiliates.

Net oil-equivalent production

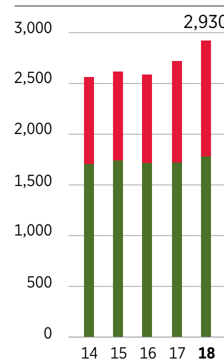
Thousands of barrels per day



Affiliates
Europe
Australia/Oceania
Asia
Africa
Other Americas
United States

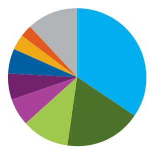
Net production liquids & natural gas

Thousands of barrels per day



Natural gas
Liquids

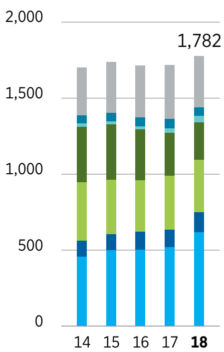
2018 net liquids production by country*
Percentage



United States	34.7%
Kazakhstan	17.7%
Nigeria	11.2%
Indonesia	6.3%
Angola	6.0%
Canada	5.8%
Thailand	3.7%
Republic of Congo	2.7%
Other	11.9%

* Includes equity share in affiliates.

Net liquids production
Thousands of barrels per day



Affiliates
Europe
Australia/Oceania
Asia
Africa
Other Americas
United States

Net liquids production

Thousands of barrels per day	2018	2017	2016	2015	2014
					Year ended December 31
Consolidated Companies					
Total United States	**618**	519	504	501	456
Other Americas					
Argentina	**20**	19	20	21	21
Brazil	**10**	12	16	17	20
Canada	**103**	87	83	67	67
Total Other Americas	**133**	118	119	105	108
Africa					
Angola	**98**	103	106	110	113
Chad	**–**	–	–	–	8
Democratic Republic of the Congo	**1**	2	2	2	2
Nigeria	**200**	213	208	230	246
Republic of Congo	**49**	36	23	18	14
Total Africa	**348**	354	339	360	383
Asia					
Azerbaijan	**18**	23	30	32	26
Bangladesh	**4**	4	4	3	2
China	**16**	17	18	24	16
Indonesia	**113**	137	173	176	149
Kazakhstan	**27**	33	37	34	31
Partitioned Zone	**–**	–	–	27	78
Philippines	**3**	3	3	3	3
Thailand	**66**	69	71	66	63
Total Asia	**247**	286	336	365	368
Australia/Oceania					
Australia	**42**	27	21	21	23
Total Australia/Oceania	**42**	27	21	21	23
Europe					
Denmark	**12**	14	14	16	17
Netherlands	**–**	–	–	–	2
Norway	**–**	–	–	–	1
United Kingdom	**43**	50	43	40	32
Total Europe	**55**	64	57	56	52
Total Consolidated Companies	**1,443**	1,368	1,376	1,408	1,390
Equity Share in Affiliates					
TCO	**288**	293	285	277	259
Venezuela	**42**	52	56	59	59
Angola LNG	**9**	10	2	–	1
Total Equity Share in Affiliates	**339**	355	343	336	319
Total Worldwide	**1,782**	1,723	1,719	1,744	1,709

upstream operating data

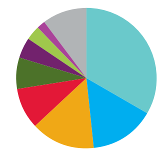
Net natural gas production*

Millions of cubic feet per day	2018	2017	2016	2015	2014
					Year ended December 31
Consolidated Companies					
Total United States	**1,034**	970	1,120	1,310	1,250
Other Americas					
Argentina	**24**	27	32	36	23
Brazil	**4**	4	5	5	6
Canada	**79**	65	55	14	10
Colombia	**82**	96	127	161	186
Trinidad and Tobago	**–**	29	74	116	112
Total Other Americas	**189**	221	293	332	337
Africa					
Angola	**59**	57	52	52	51
Chad	**–**	–	–	–	2
Democratic Republic of the Congo	**–**	1	1	1	1
Nigeria	**233**	223	159	246	236
Republic of Congo	**14**	14	11	11	11
Total Africa	**306**	295	223	310	301
Asia					
Azerbaijan	**10**	11	13	12	12
Bangladesh	**648**	642	658	720	643
China	**84**	81	51	–	–
Indonesia	**113**	163	182	185	214
Kazakhstan	**120**	132	154	138	126
Myanmar	**98**	116	128	117	99
Partitioned Zone	**–**	–	–	5	18
Philippines	**138**	129	138	122	118
Thailand	**1,022**	1,031	1,051	1,033	1,046
Total Asia	**2,233**	2,305	2,375	2,332	2,276
Australia/Oceania					
Australia	**2,304**	1,372	615	439	442
Total Australia/Oceania	**2,304**	1,372	615	439	442
Europe					
Denmark	**45**	53	48	50	51
Netherlands	**–**	–	–	–	34
United Kingdom	**133**	155	122	115	88
Total Europe	**178**	208	170	165	173
Total Consolidated Companies	**6,244**	5,371	4,796	4,888	4,779
Equity Share in Affiliates					
TCO	**387**	401	375	348	334
Venezuela	**9**	15	19	30	27
Angola LNG	**249**	245	62	3	27
Total Equity Share in Affiliates	**645**	661	456	381	388
Total Worldwide	**6,889**	6,032	5,252	5,269	5,167

* Includes natural gas consumed in operations:

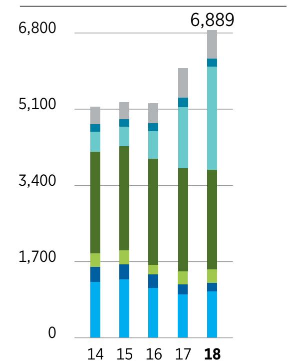
United States	**35**	37	54	66	71
International	**584**	528	432	430	452
Total	**619**	565	486	496	523

2018 net natural gas production by country*
Percentage

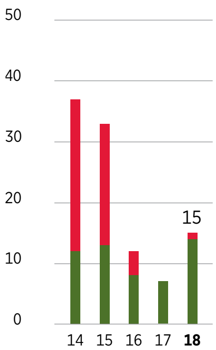


* Includes equity share in affiliates.

Net natural gas production
Millions of cubic feet per day

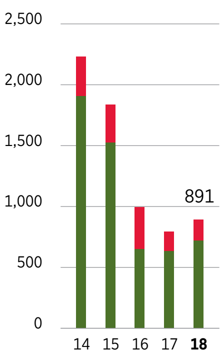


Net productive exploratory wells completed
Number of wells



Natural gas
Crude oil

Net productive development wells completed
Number of wells



Natural gas
Crude oil

Net wells completed*

Year ended December 31

	2018		2017		2016		2015		2014	
	Productive	**Dry**	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
Consolidated Companies										
United States										
Exploratory	**13**	**2**	7	1	4	1	16	4	20	12
Development	**509**	**1**	435	4	420	4	873	3	1,085	8
Total United States	**522**	**3**	442	5	424	5	889	7	1,105	20
Other Americas										
Exploratory	**1**	**1**	–	–	4	–	5	1	3	–
Development	**43**	**–**	40	–	45	–	99	–	81	–
Total Other Americas	**44**	**1**	40	–	49	–	104	1	84	–
Africa										
Exploratory	**–**	**–**	–	–	1	1	3	–	1	2
Development	**8**	**–**	34	–	17	–	9	–	9	–
Total Africa	**8**	**–**	34	–	18	1	12	–	10	2
Asia										
Exploratory	**1**	**–**	–	–	3	–	5	1	7	2
Development	**289**	**5**	246	2	470	6	828	5	1,025	4
Total Asia	**290**	**5**	246	2	473	6	833	6	1,032	6
Australia/Oceania										
Exploratory	**–**	**–**	–	–	–	–	1	4	3	–
Development	**1**	**–**	–	–	4	–	4	–	9	–
Total Australia/Oceania	**1**	**–**	–	–	4	–	5	4	12	–
Europe										
Exploratory	**–**	**1**	–	1	–	–	3	–	3	–
Development	**2**	**–**	4	–	3	–	2	–	2	–
Total Europe	**2**	**1**	4	1	3	–	5	–	5	–
Total Consolidated Companies	**867**	**10**	766	8	971	12	1,848	18	2,248	28
Equity Share in Affiliates										
Exploratory	**–**	**–**	–	–	–	–	–	–	–	–
Development	**39**	**–**	36	–	38	–	26	–	25	1
Total Equity Share in Affiliates	**39**	**–**	36	–	38	–	26	–	25	1
Total Worldwide	**906**	**10**	802	8	1,009	12	1,874	18	2,273	29

* Net Wells Completed includes wholly owned wells and the sum of the company's fractional interests in jointly owned wells completed during the year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency. Some exploratory wells are not drilled with the intention of producing from the well bore. In such cases, "completion" refers to the completion of drilling. Further categorization of productive or dry is based on the determination as to whether hydrocarbons in a sufficient quantity were found to justify completion as a producing well, whether or not the well is actually going to be completed as a producer.

Net productive wells[1,2]

At December 31

	2018	2017	2016	2015	2014
Consolidated Companies					
United States					
Oil	**28,594**	29,690	31,679	33,457	32,957
Gas	**1,912**	2,380	3,633	7,186	7,098
Total United States	**30,506**	32,070	35,312	40,643	40,055
International					
Oil	**14,214**	14,560	14,781	14,538	14,017
Gas	**2,283**	2,328	2,466	2,273	2,132
Total International	**16,497**	16,888	17,247	16,811	16,149
Total Consolidated Companies	**47,003**	48,958	52,559	57,454	56,204
Equity Share in Affiliates					
Oil	**554**	550	508	490	486
Gas	**–**	2	2	2	2
Total Equity Share in Affiliates	**554**	552	510	492	488
Total Worldwide	**47,557**	49,510	53,069	57,946	56,692

[1] Net productive wells include wholly owned wells and the sum of the company's fractional interests in wells completed in jointly owned operations.
[2] Includes wells producing or capable of producing and injection wells temporarily functioning as producing wells. Wells that produce both crude oil and natural gas are classified as oil wells.

upstream operating data

Natural gas realizations*

Dollars per thousand cubic feet	2018	2017	2016	2015	2014
			Year ended December 31		
United States	**$ 1.86**	$ 2.10	$ 1.59	$ 1.92	$ 3.90
International	**6.29**	4.62	4.02	4.53	5.78

* U.S. natural gas realizations are based on revenues from net production. International natural gas realizations are based on revenues from liftings and include equity share in affiliates.

Liquids realizations*

Dollars per barrel	2018	2017	2016	2015	2014
			Year ended December 31		
United States	**$ 58.17**	$ 44.53	$ 35.00	$ 42.70	$ 84.13
International	**64.25**	49.46	38.61	46.52	90.42

* U.S. liquids realizations are based on revenues from net production and include intercompany sales at transfer prices that are at estimated market prices. International liquids realizations are based on revenues from liftings and include equity share in affiliates.

Natural gas sales*

Millions of cubic feet per day	2018	2017	2016	2015	2014
			Year ended December 31		
United States	**3,481**	3,331	3,317	3,913	3,995
International	**5,604**	5,081	4,491	4,299	4,304
Total	**9,085**	8,412	7,808	8,212	8,299

* International sales include equity share in affiliates.

Natural gas liquids sales*

Thousands of barrels per day	2018	2017	2016	2015	2014
			Year ended December 31		
United States	**110**	30	30	26	20
International	**34**	29	24	24	28
Total	**144**	59	54	50	48

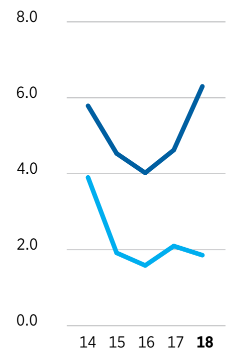
* International sales include equity share in affiliates.

Exploration and development costs*

Millions of dollars	2018	2017	2016	2015	2014
			Year ended December 31		
United States					
Exploration	**$ 782**	$ 729	$ 913	$ 1,144	$ 1,222
Development	**6,245**	4,346	3,814	6,275	8,207
Other Americas					
Exploration	**161**	81	94	128	196
Development	**856**	944	1,631	2,048	3,226
Africa					
Exploration	**64**	57	187	370	666
Development	**711**	1,136	2,014	3,701	3,771
Asia					
Exploration	**93**	99	119	413	543
Development	**1,095**	1,324	1,866	3,924	4,363
Australia/Oceania					
Exploration	**56**	79	71	259	396
Development	**845**	2,580	3,733	6,715	7,182
Europe					
Exploration	**38**	148	37	108	245
Development	**278**	121	550	995	887
Total Consolidated Companies					
Exploration	**$ 1,194**	$ 1,193	$ 1,421	$ 2,422	$ 3,268
Development	**10,030**	10,451	13,608	23,658	27,636

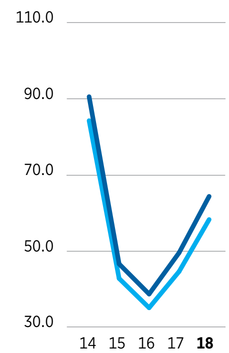
* Consolidated companies only. Excludes costs of property acquisitions.

Natural gas realizations
Dollars per thousand cubic feet



■ International*
■ United States
* Includes equity share in affiliates.

Liquids realizations
Dollars per barrel



■ International*
■ United States
* Includes equity share in affiliates.

downstream

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

Photo: Commenced first production at the new hydrogen plant as part of the modernization project at the Richmond refinery in California.

highlights

Downstream has a strong presence in the refining, marketing, trading and transportation of fuels and in the manufacturing and distribution of lubricants, additives and petrochemicals.

business strategies

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

- Sustaining world-class operational excellence.
- Driving earnings across the feedstock-to-customer value chain.
- Pursuing targeted growth opportunities.
- Creating enterprise value.

Fundamental to the company's competitive position and success is the focus on operational excellence in order to drive strong reliability and safety performance.

downstream portfolio overview

The company continues to seek leading returns and to execute capital projects and strategic milestones with excellence. Efforts to grow earnings include aligning the highest-return markets and sales channels with manufacturing assets, achieving sustainable cost efficiencies, and applying innovative technologies. The company targets investments to strengthen leading fuels value chains and to selectively grow petrochemicals, additives and lubricants. Downstream plays a strategic role in Chevron's integrated portfolio, particularly in commercial support, processing of equity crudes, transfer of technology and organizational capabilities.

2018 accomplishments

- Continued strong performance in personal and process safety by outperforming on loss-of-containment incidents, motor vehicle crash rates and spill volume targets.
- Reported earnings of $3.8 billion.
- Chevron Phillips Chemical Company (CPChem) commenced operations of its world-scale ethane cracker at the Cedar Bayou facility as part of the U.S. Gulf Coast Petrochemicals Project, and reached design capacity during second quarter.
- Reached a final investment decision for a lubricant additive blending and shipping plant in Ningbo, China.
- Commenced first production at the new hydrogen plant as part of the modernization project at the Richmond refinery in California.
- Continued growth of Chevron-branded retail stations in northwestern Mexico, expanding to 135 stations opened by year-end.
- Formed joint venture to expand ExtraMile convenience store offerings, growing to 829 stores at year-end.
- Completed the sale of the Cape Town refinery and marketing and lubricants businesses in South Africa and Botswana.

2019 outlook

The downstream business continues to focus on growing earnings and delivering leading returns. Key objectives include:

- Maintaining focus on safety and system reliability with emphasis on improving the effectiveness of safeguards related to asset integrity and loss of containment.
- Delivering on cost management initiatives and efforts.
- Advancing projects that further enhance energy efficiency, high-value product yield and refinery feedstock flexibility, including the completion of the Richmond Modernization Project.
- Progressing projects in the chemicals manufacturing business that add capacity and leverage market positions to capture global opportunities, including a final investment decision for GS Caltex's mixed-feed cracker olefins project at the Yeosu Refinery in South Korea.
- Pursuing opportunities to strengthen fuels value chains through targeted investments, including signing an agreement to acquire a refinery located in Pasadena, Texas, in January 2019.
- Continuing development of the company's renewable fuels portfolio, including gasoline, jet, diesel and natural gas.

Downstream financial and operating highlights

(Includes equity share in affiliates)

Millions of dollars	2018	2017
Earnings	**$ 3,798**	$ 5,214
Refinery crude oil inputs (Thousands of barrels per day)	**1,608**	1,661
Refinery capacity at year-end (Thousands of barrels per day)	**1,627**	1,738
U.S. gasoline and jet fuel yields (Percent of U.S. refinery production)	**61%**	66%
Refined product sales (Thousands of barrels per day)	**2,655**	2,690
Motor gasoline sales (Thousands of barrels per day)	**963**	990
Olefin and polyolefin sales (Thousands of metric tons per year)	**4,502**	3,915
Specialty, aromatic and styrenic sales (Thousands of metric tons per year)	**3,336**	2,399
Number of marketing retail outlets at December 31	**12,896**	13,504
Capital expenditures	**$ 2,193**	$ 2,190

refining and marketing

The company's refining and marketing activities are coordinated by two geographic businesses, Americas Products and International Products, each focused on optimizing the fuels value chain from crude to customer. The activities of each business include securing raw materials, manufacturing and blending products at its refineries, and selling finished products through its retail and commercial networks. The company has complex refining assets concentrated in the United States and Asia-Pacific.

Chevron continues to leverage proprietary technology, incorporating its patented cleaning additive, Techron, in these markets in order to maintain a leading position in branded fuels.

In 2018, the company completed comprehensive fuel-economy evaluations of its gasolines against its leading competitors. These evaluations leveraged Chevron's deep technical expertise in engine technology, test methods, and statistical data analysis to prove that Chevron's gasolines provide unbeatable fuel economy, which supported the launch of the new Techron "Proven, Unbeatable Mileage" campaign.

Americas Products

The business serves retail and commercial customers in North America and Latin America through the Chevron and Texaco brands. The company supplies customers at approximately 8,900 Chevron- and Texaco-branded retail outlets and approximately 40 airports across these markets.

The Americas Products portfolio includes four wholly owned refineries in North America with a crude capacity of approximately 930,000 barrels per day. All of these refineries leverage Chevron's proprietary hydroprocessing technologies, which provide the flexibility to process a wide range of feedstocks into clean, high-value products. The network of service stations in Americas Products is supported and served by 30 proprietary fuel terminals. During 2018, the business sold a daily average of approximately 1.5 million barrels of gasoline and other refined products. In January 2019, the company signed an agreement to acquire a refinery located in Pasadena, Texas.

Improving refining flexibility, reliability and yield

During 2018, the company continued work on projects to improve refinery flexibility and reliability. At the Richmond refinery in California, the modernization project continued to progress. The project scope includes replacement of some of the refinery's processing equipment with more modern technology that meets or exceeds some of the nation's toughest applicable environmental and safety standards. First production commenced at the new hydrogen plant in November 2018, and full operation of the project is expected in 2019.

At the Salt Lake City refinery in Utah, construction continued on the alkylation retrofit project with the arrival of more than 100 process modules expected over the next several months. Project start-up is expected in 2020.

Photo: Chevron formed a joint venture to expand ExtraMile convenience store offerings, growing to 829 stores by year-end.

Sustaining a focused marketing portfolio

Across the markets that Chevron serves in the United States and Latin America, the company enjoys strong market positions and continues to capture opportunities to grow market share of motor gasoline and diesel fuel under the Chevron and Texaco brands. In 2018, Chevron continued to grow in northwestern Mexico, securing additional terminal capacity and expanding to 135 branded stations. Through a joint venture, Chevron extended its ExtraMile convenience store brand to 829 locations in the western United States. These opportunities, coupled with the company's growth strategy, are expected to enable the Chevron and Texaco brands to maintain leading market positions.

International Products

The business provides premium-quality Caltex-branded fuel products to retail and commercial customers in Asia-Pacific and the Middle East.

The International Products business has three large refineries in South Korea, Singapore and Thailand. The refinery network, including the company's share of affiliates, has a crude capacity of approximately 700,000 barrels per day.

The company and its affiliates serve customers at approximately 4,000 Caltex-branded retail outlets and approximately 50 airports in Asia-Pacific and the Middle East. The business sold a daily average of 1.2 million barrels of refined products in 2018.

Chevron completed the sale of its interests in the Cape Town refinery, along with the marketing and lubricants businesses in South Africa and Botswana in September 2018.

improving performance with cutting-edge technology

Manufacturing sites are applying technology to improve reliability, increase asset productivity and optimize plant performance

Chevron is leveraging advanced digital technologies that employ wireless connectivity, sensors, plant and process data analytics, and mobile worker solutions to improve safety, enhance equipment monitoring and reduce maintenance costs.

In addition, Chevron developed and is deploying a series of novel coating technologies that reduce corrosion rates and extend equipment life for tanks.

Photo: The Richmond refinery modernization project is designed to improve reliability.

Refineries strategically positioned

The Asia-Pacific refining assets are well positioned to supply growing demand in this region. The 50 percent-owned, GS Caltex operated Yeosu Refinery in South Korea remains one of the world's largest and is targeted for additional investment with the addition of olefins production capability. The company's 60.6 percent-owned refinery in Map Ta Phut, Thailand, continues to supply high-quality petroleum products through the Caltex brand in the Thailand market.

Singapore Refining Company (SRC), Chevron's 50 percent-owned joint venture, processes up to 276,000 barrels of crude per day and manufactures a wide range of petroleum products for customers in the region. Recent upgrades have enabled SRC to produce higher-value gasoline that meets stricter emission standards while increasing energy efficiency, reducing emissions and lowering operating costs. The company continues to progress evaluation and development of upgrading projects to convert low-value products into higher-value products.

Sustaining a focused marketing portfolio

The company continues to expand in selected growth markets by executing its strategic retail network plan focusing on investor trade class sites, strengthening its retail networks, improving fuels supply chains, and widening third-party partnerships and alliances with growth efforts in Thailand, the Philippines and Malaysia.

renewable fuels

Chevron is pursuing opportunities with technology providers and start-up companies to develop dairy digester and methane capture systems. A large source of methane emissions to the atmosphere is livestock digestive gases and waste. The captured methane is treated to commercial natural gas specifications and can be used to fuel compressed natural gas vehicles. It can also be used to produce renewable hydrogen for use in refineries or for fuel cell vehicles.

lubricants

Chevron is among the leading global developers and marketers of lubricants and is a leading global producer of premium base oil, with a total capacity of approximately 58,000 barrels per day. The company provides high-quality lubricants products to meet the needs of commercial, industrial, retail and marine customers. Lubricants and coolants are produced and marketed through the Havoline, Delo, Ursa, Meropa, Rando, Clarity and Taro product lines under three brands: Chevron, Texaco and Caltex.

Chevron enables its base oil customers to optimize formulations worldwide by providing a consistent global product slate of premium base oils. Chevron's global supply network includes base oil manufacturing facilities at the refineries in Richmond, California; Pascagoula, Mississippi; and Yeosu, South Korea. It also includes 15 equity-blending facilities, multiple contract-blending facilities and distribution hubs.

Chevron continues to develop products to meet existing and future demand through strategic partnerships with original equipment manufacturers and advanced research at technology centers in the United States, Belgium and Singapore. This research includes the development of high-performing renewable products meeting stringent environmental standards and engine oils that offer fuel economy retention benefits.

Chevron has a technology partnership with an equity affiliate to co-develop high-performance synthetic base oil from plant-based renewable feedstocks.

Chevron's ICONIC Lubrificantes joint venture in Brazil has the largest finished lubricants market share in Brazil. In September 2018, Chevron announced its new Taro Ultra range of International Maritime Organization (IMO) 2020-ready marine cylinder lubricants formulated to meet IMO's global low-sulphur cap that is effective January 2020.

Chevron focuses on retail customer experience

The company is applying technology to enhance the customer experience at fueling stations around the world

- In Singapore, Chevron has launched the country's first integrated fuel payment mobile app, which offers motorists a faster mode of payment from the convenience of their car. The fuel payment app also helps drivers easily locate a nearby Caltex service station, enjoy automatic loyalty points collection, exclusive mobile offers and electronic receipts at their fingertips.
- In the United States, Chevron has partnered with PayPal to develop and pilot a mobile payment solution that enables the 75 million local PayPal account holders to purchase fuel and car washes.
- With Honda, Chevron is developing technology that enables drivers to pay for fuel and convenience store items in-dash from their vehicle.

Photo: Ad campaign materials demonstrating the new CaltexGo app.

additives

Chevron's Oronite subsidiary is a world-leading developer, manufacturer and marketer of quality additives that improve the performance of lubricants and fuels. Oronite conducts research and development for additive component and blended packages to meet the increasingly demanding needs of engine and equipment performance, as well as more stringent regulatory requirements. At year-end 2018, Oronite manufactured, blended, or conducted research and development at 10 locations around the world.

Oronite lubricant additives are blended with refined base oils to produce finished lubricants used primarily in engine applications, including passenger cars, heavy-duty diesel trucks, buses, ships, locomotives and motorcycles. Typically, several additive components, such as dispersants, detergents, oxidation, corrosion and rust inhibitors, and viscosity-index improvers, are combined to meet desired performance specifications. Specialty additives are also marketed for other applications, including power transmission fluids and hydraulic oils.

Oronite fuel additives are used to improve engine performance and extend engine life. The main additive applications are for blended gasoline and gasoline aftermarket products. Many fuel additive packages are unique and blended specifically to individual customer specifications, the most recognized being the additive package branded as Techron and used exclusively in Chevron, Texaco and Caltex fuels and in Techron Concentrate Plus fuel system cleaner. Fuel performance standards vary for customers throughout the world, and specific packages are tailored for each region's markets.

Expanding in key growth markets

Oronite has a strong foundation to support long-term international growth with its global manufacturing coverage and versatile cross-continent supply network. The majority of global volume growth is expected in Asia, where Oronite's Singapore plant is the largest additives manufacturing plant in the region.

In June 2018, a final investment decision was reached for a lubricant additive blending and shipping plant in Ningbo, China, with groundbreaking activities taking place in October 2018. Estimated completion of the facility is 2020, with commercial production anticipated to begin in 2021.

Photo: The groundbreaking ceremony for a new additive manufacturing plant in Ningbo, China took place in October 2018.

Oronite leverages technology to address evolving engine design and regulatory requirements

The company is advancing product line technology to meet industry needs

Oronite continues to develop new products that provide improved performance for evolving engine designs and regulatory requirements, including the development of:

- Additives packages for newer, downsized, higher-performance automobile engines.
- Additive formulations designed to benefit natural gas engines.
- Additives used to satisfy lower marine bunker fuel sulphur requirements.

Photo: A researcher at Oronite's laboratories in Richmond, California, uses advanced chromatography techniques to aid in the design of additives required for multigrade engine oils.

petrochemicals

The company has a broad, worldwide petrochemicals portfolio producing both olefins and aromatics. The company's petrochemical activities are conducted through two joint ventures, CPChem and GS Caltex.

CPChem

CPChem is a 50 percent-owned affiliate. It is one of the world's leading producers of olefins, polyolefins and alpha olefins and is a leading supplier of aromatics and polyethylene pipe, in addition to participating in the specialty chemical and specialty plastics markets. At year-end 2018, CPChem owned or had joint-venture interests in 28 manufacturing facilities and two research and development centers around the world. CPChem markets its products through leading brands such as Marlex, AlphaPlus, Scentinel, Synfluid and Soltrol.

Leveraging advantaged feedstock position

In March 2018, as part of the U.S. Gulf Coast Petrochemical Project, CPChem commenced operations of a new ethane cracker with an annual design capacity of 1.5 million metric tons of ethylene at the Cedar Bayou facility, and reached design capacity during second quarter 2018. The project benefits from advantaged feedstock sourced from shale resource development in North America. CPChem's strong positions in North America and the Middle East allow it to leverage the availability of competitive feedstocks and meet growing global demand.

Photo: Start-up of the new ethane cracker was achieved at CPChem's U.S. Gulf Coast Petrochemical Project in March 2018.

GS Caltex

Chevron also maintains an important role in the petrochemicals business through the operations of GS Caltex, a 50 percent-owned affiliate located in South Korea. GS Caltex is a leading manufacturer of petrochemicals. With one of the largest single-facility aromatics plants in the world, the Yeosu complex has a production capacity of 2.8 million metric tons per year of aromatics, including benzene, toluene and xylene. These are base chemicals used to produce a range of products, including adhesives, plastics and textile fibers. GS Caltex also produces polypropylene, which is used to make automotive and home appliance parts, food packaging, laboratory equipment, and textiles. GS Caltex expects to reach a final investment decision in first quarter 2019 to build an olefins mixed-feed cracker and polyethylene unit within the existing refining and aromatics facilities. The new plant is expected to supply an additional 700,000 tons of ethylene and 500,000 tons of polyethylene a year to local markets when it is completed.

consumers benefit from CPChem's research and technology

Research and development are key priorities for CPChem

CPChem currently holds more than 2,500 patents and patent applications in the areas of petrochemical and polymer research, new catalyst development, and product and process development.

- The proprietary MarTECH loop slurry process for polyethylene production is a widely licensed process. CPChem successfully scaled up application of the MarTECH loop slurry technology in two world-scale-sized polyethylene units commissioned as part of CPChem's U.S. Gulf Coast project.
- The Aromax technology is the lowest-cost process for on-purpose production of benzene.
- Other proprietary technologies include on-purpose 1-hexene technology and proprietary primary normal alpha olefin technology.

Photo: CPChem successfully applied the MarTECH loop slurry technology in the two polyethylene units as part of the U.S. Gulf Coast Petrochemicals project.

supply and trading

Supply and trading (S&T) provides commercial support to upstream and downstream. S&T applies its knowledge of commodity markets, the crude-to-customer value chain and transportation logistics in the crude oil, natural gas, and refined products markets to maximize the value of enterprise assets and enable the commercial success of upstream and downstream. S&T buys, sells and supplies crude oil, refined products, gas and gas liquids to support the company's crude and gas production operations and its refining and marketing network. Activities include the integration of equity crude oil from the upstream operations into the company's refining network and the commercialization of Chevron's equity liquefied natural gas (LNG) volumes.

transportation

The company's transportation businesses, including pipeline and shipping operations, are responsible for transporting a variety of products to customers worldwide. Transportation activities are aligned with the needs of the upstream, refining and marketing businesses.

Pipeline

Chevron owns and operates a network of crude oil, natural gas and product pipelines and other infrastructure assets in the United States. Chevron's Pipeline Control Center in Houston, Texas, utilizes advanced leak detection systems and damage prevention systems to safely move more than 1.4 million barrels of oil-equivalent per day. In addition, Chevron operates pipelines for its 50 percent-owned CPChem affiliate. The company also has direct and indirect interests in other U.S. and international pipelines.

Refer to pages 23 through 25 in the upstream section for information on the West African Gas Pipeline, the Baku-Tbilisi-Ceyhan pipeline, the Western Route Export Pipeline and the Caspian Pipeline Consortium.

Shipping

Chevron's corporate marine center of expertise provides safe, reliable and cost-competitive marine transportation, manages marine risk and provides marine operational, technical and commercial support to the enterprise, with marine specialists in 20 countries. The company operates a fleet of conventional crude tankers, product carriers and LNG carriers. These vessels transport crude oil, LNG, refined products and feedstocks in support of global upstream and downstream businesses.

investing in the future of energy

Chevron is proud to invest in breakthrough technologies that enable the future of energy

The company addresses key business needs now and into the future through the pursuit and integration of new business solutions and innovative energy technologies. In 2018, the company managed more than $350 million in venture capital investments and introduced or deployed more than 20 new technologies across the enterprise. Chevron also launched the Future Energy Fund with an initial $100 million commitment targeted at reducing emissions from oil and gas and investing in low-carbon energy value chains. Some examples of recent investments include:

- A November 2018 investment in ChargePoint, which is charging technology designed to support every aspect of electric vehicle charging, focusing on fleet vehicle solutions.
- In December 2018, the fund invested in Natron Energy contributing to Natron's development of stationary energy storage systems at electric vehicle charging stations.
- A third investment was made in December 2018 to support Carbon Engineering, which will help commercialize the next generation of carbon capture technology while advancing efforts in carbon conversion.

Photo: Chevron is proud to invest in breakthrough technologies that enable the future of energy.

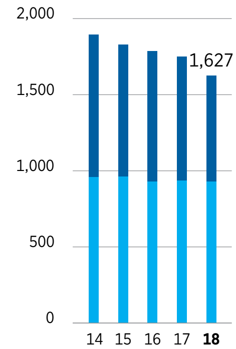
downstream operating data

Refinery capacities and crude oil inputs

Thousands of barrels per day	Refinery capacity At December 31, 2018	Refinery crude oil inputs (Year ended December 31) 2018	2017	2016	2015	2014
United States – Consolidated						
El Segundo, California	**269**	**273**	251	267	258	221
Kapolei, Hawaii[1]	**–**	**–**	–	37	47	47
Pascagoula, Mississippi	**351**	**332**	349	355	322	329
Richmond, California	**257**	**249**	248	188	245	229
Salt Lake City, Utah	**55**	**51**	53	53	52	45
Total United States – Consolidated	**932**	**905**	901	900	924	871
International – Consolidated						
Canada – Burnaby, British Columbia[2]	**–**	**–**	40	51	46	49
South Africa – Cape Town[3]	**–**	**49**	68	78	69	72
Thailand – Map Ta Phut	**157**	**160**	152	162	164	141
Total International – Consolidated	**157**	**209**	260	291	279	262
International – Equity Shares in Affiliates						
Australia – Brisbane (50%)[4]	**–**	**–**	–	–	12	50
Australia – Sydney (50%)[4]	**–**	**–**	–	–	–	39
New Zealand – Whangarei (11.4%)[5]	**–**	**–**	–	–	5	13
Pakistan – Karachi (<1%)	**–**	**–**	3	3	3	4
Singapore – Pulau Merlimau (50%)	**138**	**116**	127	121	118	109
South Korea – Yeosu (50%)	**400**	**378**	370	373	361	342
Total International – Equity Share in Affiliates	**538**	**494**	500	497	499	557
Total International	**695**	**703**	760	788	778	819
Total Worldwide	**1,627**	**1,608**	1,661	1,688	1,702	1,690

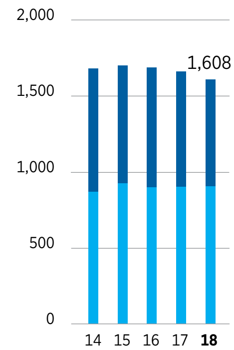
[1] Chevron sold its interest in this refinery in November 2016.
[2] Chevron sold its interest in this refinery in September 2017.
[3] Chevron sold its interest in this refinery in September 2018.
[4] Chevron sold its interest in Caltex Australia Limited in April 2015.
[5] Chevron sold its interest in this refinery in June 2015.

Refinery capacity at December 31
Thousands of barrels per day



■ International*
■ United States
*Includes equity share in affiliates.

Refinery crude oil inputs
Thousands of barrels per day



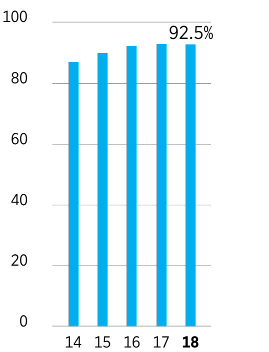
■ International*
■ United States
*Includes equity share in affiliates.

Refinery capacities at year-end 2018

Thousands of barrels per day	Chevron share of capacities[1] Atmospheric distillation[2]	Catalytic cracking[3]	Hydro-cracking[4]	Residuum conversion[5]	Lubricants[6]
United States – Consolidated					
El Segundo, California	**269**	**67**	**50**	**69**	**–**
Pascagoula, Mississippi	**351**	**79**	**107**	**94**	**25**
Richmond, California	**257**	**81**	**147**	**–**	**20**
Salt Lake City, Utah	**55**	**14**	**–**	**9**	**–**
Total United States – Consolidated	**932**	**241**	**304**	**172**	**45**
International – Consolidated					
Thailand – Map Ta Phut	**157**	**37**	**–**	**–**	**–**
Total International – Consolidated	**157**	**37**	**–**	**–**	**–**
International – Equity Shares in Affiliates[7]					
Singapore – Pulau Merlimau (50%)	**138**	**22**	**16**	**15**	**–**
South Korea – Yeosu (50%)	**400**	**73**	**77**	**–**	**12**
Total International – Equity Share in Affiliates	**538**	**95**	**93**	**15**	**12**
Total International	**695**	**132**	**93**	**15**	**12**
Total Worldwide	**1,627**	**373**	**397**	**187**	**57**

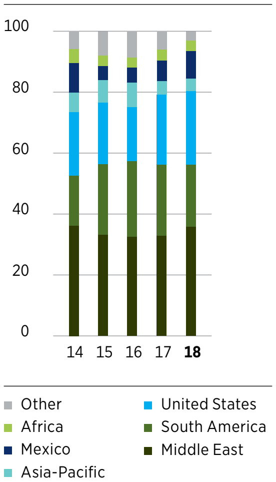
[1] Capacities represent typical calendar-day processing rates for feedstocks to process units, determined over extended periods of time. Actual rates may vary depending on feedstock qualities, maintenance schedules and external factors.
[2] Atmospheric distillation is the first distillation cut. Crude oil is heated at atmospheric pressure and separates into a full boiling range of products, such as liquid petroleum gases, gasoline, naphtha, kerosene, gas oil and residuum.
[3] Catalytic cracking uses solid catalysts at high temperatures to produce gasoline and other lighter products from gas-oil feedstocks.
[4] Hydrocracking combines feedstocks and hydrogen at high pressure and temperature in the presence of a catalyst to reduce impurities and produce lighter products, such as gasoline, diesel and jet fuel.
[5] Residuum conversion includes thermal cracking, visbreaking and coking processes, which rely primarily on heat to convert heavy residuum feedstock to the maximum production of lighter boiling products.
[6] Lubricants capacity is based on dewaxed base oil production.
[7] Excludes the Pakistan refinery affiliate.

Worldwide refinery crude distillation utilization*
Percent of average capacity



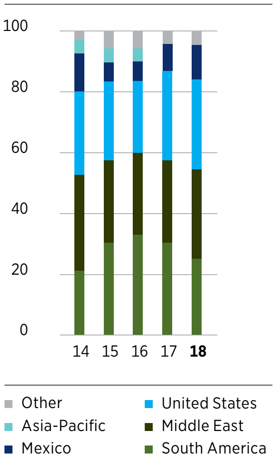
* Includes equity share in affiliates.

Sources of crude oil input for worldwide refineries*
Percentage of total input



* Consolidated companies only.

Sources of crude oil input for U.S. refineries*
Percentage of total input



* Consolidated companies only.

Refinery crude distillation utilization

(Includes equity share in affiliates)

	Year ended December 31				
Percentage of average capacity	**2018**	2017	2016	2015	2014
United States	**97.1**	98.1	93.4	96.1	90.9
Asia-Pacific	**94.2**	92.1	93.4	86.2	84.9
Africa-Pakistan	**45.6**	62.1	71.3	63.4	65.6
Other	**–**	72.5	91.9	83.7	89.9
Worldwide	**92.5**	92.7	92.0	89.8	86.8

Sources of crude oil input for worldwide refineries*

	Year ended December 31				
Percentage of total input	**2018**	2017	2016	2015	2014
Middle East	**35.8**	32.8	32.4	33.1	36.2
South America	**20.4**	23.5	24.9	23.3	16.3
United States	**24.2**	23.0	17.8	20.1	21.0
Asia-Pacific	**4.0**	4.3	8.1	7.4	6.3
Mexico	**9.1**	6.8	4.8	4.7	9.7
Africa	**3.6**	3.5	3.4	3.4	4.7
Other	**2.9**	6.1	8.6	8.0	5.8
Total	**100.0**	100.0	100.0	100.0	100.0

* Consolidated companies only.

Sources of crude oil input for U.S. refineries*

	Year ended December 31				
Percentage of total input	**2018**	2017	2016	2015	2014
South America	**25.1**	30.3	32.9	30.3	21.2
Middle East	**29.3**	27.1	27.1	27.1	31.4
United States – excluding Alaska North Slope	**22.1**	22.1	20.0	20.6	22.5
United States – Alaska North Slope	**7.6**	7.4	3.6	5.5	5.0
Mexico	**11.2**	8.8	6.3	6.1	12.6
Asia-Pacific	**–**	–	4.3	4.7	4.3
Other	**4.7**	4.3	5.8	5.7	3.0
Total	**100.0**	100.0	100.0	100.0	100.0

* Consolidated companies only.

Refinery production of refined products*

	Year ended December 31				
Thousands of barrels per day	**2018**	2017	2016	2015	2014
United States					
Gasoline	**442**	444	450	439	413
Diesel/Gas oil	**178**	183	188	205	184
Jet fuel	**229**	210	197	197	196
Fuel oil	**42**	31	34	38	43
Other	**133**	128	120	127	115
Total United States	**1,024**	996	989	1,006	951
International					
Gasoline	**60**	88	102	94	87
Diesel/Gas oil	**83**	96	110	105	97
Jet fuel	**20**	26	28	27	25
Fuel oil	**24**	28	31	26	26
Other	**27**	30	32	38	30
Total International	**214**	268	303	290	265
Worldwide					
Gasoline	**502**	532	552	533	500
Diesel/Gas oil	**261**	279	298	310	281
Jet fuel	**249**	236	225	224	221
Fuel oil	**66**	59	65	64	69
Other	**160**	158	152	165	145
Total Worldwide	**1,238**	1,264	1,292	1,296	1,216

* Consolidated companies only.

downstream operating data

Refined product sales

Thousands of barrels per day	2018	2017	2016	2015	2014
					Year ended December 31
United States					
Gasoline	**627**	625	631	621	615
Diesel/Gas oil	**188**	179	182	215	217
Jet fuel	**255**	242	242	232	222
Fuel oil	**48**	48	59	59	63
Other[1]	**100**	103	99	101	93
Total United States	**1,218**	1,197	1,213	1,228	1,210
International[2]					
Gasoline	**336**	365	382	389	403
Diesel/Gas oil	**446**	490	468	478	498
Jet fuel	**276**	274	261	271	249
Fuel oil	**177**	162	144	159	162
Other[1]	**202**	202	207	210	189
Total International	**1,437**	1,493	1,462	1,507	1,501
Worldwide[2]					
Gasoline	**963**	990	1,013	1,010	1,018
Diesel/Gas oil	**634**	669	650	693	715
Jet fuel	**531**	516	503	503	471
Fuel oil	**225**	210	203	218	225
Other[1]	**302**	305	306	311	282
Total Worldwide	**2,655**	2,690	2,675	2,735	2,711
[2] Includes share of equity affiliates' sales:	**373**	366	377	420	475

[1] Other primarily includes naphtha, lubricants, asphalt and coke.
[2] Includes share of equity affiliates' sales.

Natural gas liquid sales
(Includes equity share in affiliates)

Thousands of barrels per day	2018	2017	2016	2015	2014
					Year ended December 31
United States	**74**	109	115	127	121
International	**62**	64	61	65	58
Total	**136**	173	176	192	179

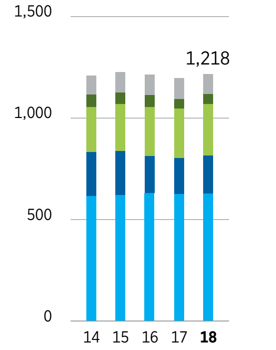
Marketing retail outlets[1,2]

At December 31

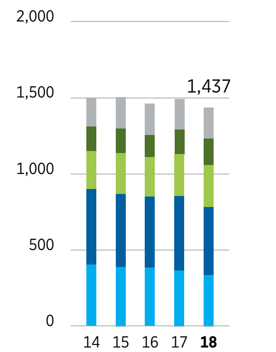
	2018		2017		2016		2015		2014	
	Company	**Other**	Company	Other	Company	Other	Company	Other	Company	Other
United States	**313**	**7,534**	321	7,422	325	7,489	366	7,493	380	7,550
Canada	**–**	**–**	–	–	137	43	138	41	150	20
Latin America	**24**	**1,065**	29	857	38	773	48	716	62	679
Asia-Pacific	**125**	**1,385**	133	1,400	146	1,430	174	1,529	204	1,530
Africa-Pakistan	**–**	**–**	183	651	187	642	191	633	343	1,023
Total	**462**	**9,984**	666	10,330	833	10,377	917	10,412	1,139	10,802

[1] Excludes outlets of equity affiliates totaling 2,450, 2,508, 2,599, 2,651 and 4,436 for 2018, 2017, 2016, 2015 and 2014, respectively.
[2] Company outlets are motor vehicle outlets that are company owned or leased. These outlets may be either company operated or leased to a dealer. Other outlets consist of all remaining branded outlets that are owned by others and supplied with branded products.

U.S. refined product sales
Thousands of barrels per day

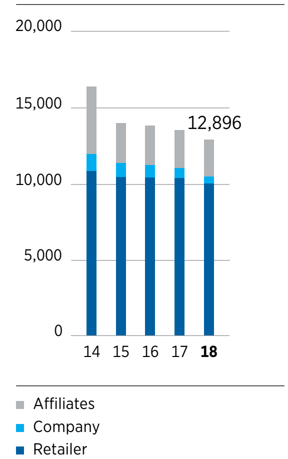


International refined product sales*
Thousands of barrels per day



*Includes equity share in affiliates.

Marketing retail outlets
Number of outlets



CPChem plant capacities and products at year-end 2018[1]

Thousands of metric tons per year	Benzene	Cyclohexane	Ethylene	Normal alpha olefins	Polyethylene	Propylene	Styrene	Other[3]
	CPChem share of capacity by product[2]							
United States – Wholly Owned								
Baytown, Texas (Cedar Bayou)	–	–	2,434	1,060	980	465	–	√
Borger, Texas	–	–	–	–	–	–	–	√
Conroe, Texas	–	–	–	–	–	–	–	√
Old Ocean, Texas (Sweeny)	–	–	1,991	–	1,000	395	–	–
Orange, Texas	–	–	–	–	440	–	–	–
Pasadena, Texas	–	–	–	–	985	–	–	–
Pascagoula, Mississippi	725	–	–	–	–	–	–	–
Port Arthur, Texas	–	480	855	–	–	350	–	–
Seven other locations	–	–	–	–	–	–	–	√
Total United States – Wholly Owned	725	480	5,280	1,060	3,405	1,210	–	√
United States – Affiliates								
Allyn's Point, Connecticut (50%)	–	–	–	–	–	–	–	√
Hanging Rock, Ohio (50%)	–	–	–	–	–	–	–	√
Joliet, Illinois (50%)	–	–	–	–	–	–	–	√
Marietta, Ohio (50%)	–	–	–	–	–	–	–	√
St. James, Louisiana (50%)	–	–	–	–	–	–	475	–
Torrance, California (50%)	–	–	–	–	–	–	–	√
Total United States – Affiliates	–	–	–	–	–	–	475	√
Total United States	725	480	5,280	1,060	3,405	1,210	475	√
International – Wholly Owned								
Belgium, Beringen	–	–	–	–	–	–	–	√
Belgium, Tessenderlo	–	–	–	–	–	–	–	√
Total International – Wholly Owned	–	–	–	–	–	–	–	√
International – Affiliates								
Colombia, Cartagena (50%)	–	–	–	–	–	–	–	√
Qatar, Mesaieed (49%)	–	–	255	200	395	–	–	–
Qatar, Ras Laffan (6%)	–	–	340	–	–	–	–	–
Saudi Arabia, Al Jubail (50%)	425	180	105	–	–	75	375	√
Saudi Arabia, Al Jubail (35%)	–	–	425	35	385	155	–	√
Singapore (50%)	–	–	–	–	200	–	–	–
Total International – Affiliates	425	180	1,125	235	980	230	375	√
Total International	425	180	1,125	235	980	230	375	√
Total Worldwide	1,150	660	6,405	1,295	4,385	1,440	850	√

[1] Includes CPChem's share of equity affiliates.
[2] Capacities represent typical calendar-day processing rates for feedstocks to process units, determined over extended periods of time. Capacities may vary from actual depending on feedstock qualities, maintenance schedules and external factors.
[3] Other includes paraxylene, polyalphaolefins, polypropylene, polystyrene, performance pipe and specialty chemicals.

Olefin, polyolefin, specialty, aromatic and styrenic sales

(Represents equity share in CPChem and GS Caltex)

Thousands of metric tons per year	2018	2017	2016	2015	2014
	Year ended December 31				
Olefin and polyolefin sales	**4,502**	3,915	3,972	4,145	4,110
Specialty, aromatic and styrenic sales	**3,336**	2,399	3,442	3,392	3,564

digital technology

digital innovation is enhancing Chevron's performance

Photo: Chevron empowers the workforce to make better, faster decisions supported by digital technologies and a culture of innovation.

digital technology

Digital ambition Chevron has a proud history of innovation. Since the company's beginning, it has embraced new technologies to drive the business forward. The world today is changing at an accelerated pace, and Chevron is changing with it. To win in a fast-changing world, the company empowers the workforce to make better, faster decisions supported by digital technologies and a culture of innovation. Chevron is transforming the way employees work and is leveraging digital technologies to solve some of the most complex challenges in the energy industry.

Driving business value Transforming the way Chevron works digitally is not just about the technology, it is about leveraging the technology to derive additional value from the business and differentiating the company's performance. The company is accelerating the deployment of digital technologies to improve revenues, reduce costs, increase reliability and improve safety. In 2018 alone, Chevron's data science and data analytics program generated more than $200 million in value across the company.

Safety Chevron's sustained focus on leveraging engineered safeguards and technology has led to continued improvements in the company's safety performance. This includes seeking new ways to protect people and the environment, including removing the workforce from high-risk situations.

Real-time location systems are being used to improve personnel control around potentially hazardous situations. With millions of crane lifts across the company's operations every year, a crane safety solution is being piloted in the Gulf of Mexico. This real-time location system uses ultra-wide band and wearable technology to alert workers when they are potentially walking under a crane load.

At the Chevron Oronite Singapore manufacturing plant, real-time location systems are used to improve safety at the facility by embedding radio-frequency identification tags in monitors worn by all plant workers. With these sensors, a "smart plant" has been created that can account for the location of all workers at all times. In high-risk processing areas, geofencing is used to control access, and in the event of an emergency, personnel can be located in real-time.

Photo: The Gulf of Mexico crane safety solution pilot alerts workers potentially moving into a high-risk area, ensuring they work safely while around cranes and heavy loads.

Revenue Using innovative technologies has enabled Chevron to enhance cash flow and earnings, while maintaining competitive margins. Application of technology enables new life from older fields and greater yields from the downstream and chemicals businesses.

The Gorgon liquefied natural gas (LNG) plant has integrated more digital technology than any facility ever built by Chevron. Real-time data is collected from thousands of sensors placed throughout the operation. Populating sophisticated optimization-algorithms with this data, the plant delivers higher throughput and reliability than could be achieved with traditional control technology. Advanced Process Control (APC) technology is being deployed across all Chevron's complex facilities world-wide. The implementation of APC at Gorgon was one of the fastest in the LNG industry, generating value of more than $240 million.

Photo: Implementation of Advanced Process Control technology at Gorgon was one of the fastest in the industry.

To support the rapid growth of Chevron's unconventional production, a suite of tools has been developed that enable the workforce to increase work throughput in a competitive, short-cycle environment. The Factory Integrated Tools (FIT) Program digitizes key processes, providing the foundation of high-quality data, transparency and visibility. Tools in this suite include: a data foundation system comprising of public data augmented with Chevron proprietary well information; a portfolio tool for scheduling and rig sequencing; and a production analysis tool to optimize completions and compare against competitor benchmarking. FIT supports key decision-making and creates a platform to accelerate performance improvement.

Cost Chevron continues its journey to reduce structural costs and improve efficiencies across its operations. Digital innovation is an important lever to enable Chevron to compete in a low-cost world.

Chevron gathers data from over one-million sensors placed throughout all global operations. This number is growing by more than 100,000 sensors every year. With streaming data from these devices, data analytics, artificial intelligence, and machine learning can be applied to provide real-time insights that improve operations around the world.

One way this data is leveraged is through integrated Decision Support Centers (DSC), which have been established in every upstream business unit. These DSCs allow Chevron to pool expertise, integrate complex workflows and centralize real-time decisions which increases operational efficiency and asset productivity.

The Drilling & Completions Decision Support Center monitors the drilling of all complex wells across the globe and centralizes key processes such as shale-and-tight focused geo-steering and fracture monitoring.

Photo: Chevron has decision support centers across upstream operations enabling real time decision making with centralized experts.

Reliability Chevron's commitment to technology captures value by managing assets more reliably.

The company is conducting autonomous inspections of critical vessels and piping in multiple company locations worldwide. In addition to using drones for aerial inspections, the company utilizes them to perform inspections in enclosed environments. This allows inspections to be completed inside confined spaces while relaying data to engineers outside.

Photo: Drones are revolutionizing inspections by collecting data while ensuring assets and personnel operate safely.

Chevron is using new sensor technology for pressure, level, and temperature monitoring to advance real-time decision making and maintenance planning. The company has created a "smart lid" on chemical tanks in the San Joaquin Valley. Using sensors creatively installed in the tank lids, this data can be collected in real-time and sent to vendors, automating the supply chain, reducing inefficiencies, and improving chemical performance reliability.

connecting employees around the world

Chevron is leveraging technology to reduce costs and improve safety

HoloLens, an augmented reality headset, connects field personnel with subject matter experts located around the world to troubleshoot problems faster and more efficiently. The company has deployed more than 150 HoloLens devices worldwide.

Photo: HoloLens and augmented reality technology enable expert troubleshooting while removing non-critical personnel from the operating environment.

Digital strategy Chevron's approach to ongoing digital innovation is uniquely designed to complement the company's culture.

The investment strategy takes a portfolio approach, balancing near-term value creation and ownership in the business with centralized projects ensuring long-term scalability and maximized value.

Innovation in the business For top-tier assets, including Permian, Tengiz, Gorgon and Wheatstone, critical focus areas have been identified where digital investments will address opportunities for material differentiation in performance.

Photo: Critical focus areas have been identified where digital investments will address opportunities for material differentiation in performance in key assets like Wheatstone.

glossary of energy and financial terms

energy terms

Acreage Land leased for crude oil and natural gas exploration and production.

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

Barrels of oil-equivalent 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 well bore and reach surface conditions.

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

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

Exploration Searching for crude oil and/or natural gas by utilizing geological 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.

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

Liquefied petroleum gas (LPG) Light gases, such as butane and propane, that can be maintained as liquids while under pressure.

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

Oil-equivalent gas 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, oil-equivalent gas* and *production-sharing contract*.

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.

Refinery utilization Represents average crude oil consumed in fuel and asphalt refineries for the year, expressed as a percentage of the refineries' average annual crude unit capacity.

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, 2018.

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 other 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 or 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.

Unconventional oil and gas resources Hydrocarbons contained in formations over very large areas with extremely low permeability that are not influenced by buoyancy. In contrast, conventional resources are contained within geologic structures/stratigraphy and float buoyantly over water. Unconventional resources include shale gas, coalbed methane, crude oil and natural gas from tight rock formations, tar sands, kerogen from oil shale, and gas hydrates that cannot commercially flow without well stimulation.

Wells Oil and gas wells are classified as either exploration or development wells. *Exploration wells* are wells drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil and gas in another reservoir. *Appraisal wells* are exploration wells drilled to confirm the results of a discovery well. *Delineation wells* are exploration wells drilled to determine the boundaries of a productive formation or to delineate the extent of a find. *Development wells* are wells drilled in an existing reservoir in a proved oil- or gas-producing area. *Completed wells* are wells in which drilling work has been completed and that are capable of producing. *Dry wells* are wells completed as dry holes, that is, wells not capable of producing in commercial quantities.

financial terms

Capital employed The sum of Chevron Corporation stockholders' equity, total debt and noncontrolling interests. Average capital employed is computed by averaging the sum of capital employed at the beginning and end of the year.

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.

Current ratio Current assets divided by current liabilities.

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.

Free cash flow The cash provided by operating activities less capital expenditures.

Goodwill An asset representing the future economic benefits arising from the other assets acquired in a business combination that are not individually identified and separately recognized.

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.

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

Net debt to capital ratio Total debt less the sum of cash and cash equivalents, time deposits, and marketable securities, as a percentage of total debt plus Chevron Corporation's stockholders' equity.

Return on capital employed (ROCE) Ratio calculated by dividing earnings (adjusted for after-tax interest expense and noncontrolling interests) by average capital employed.

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.

Return on total assets Ratio calculated by dividing earnings by average total assets. *Average total assets* is computed by averaging the sum of the beginning-of-year and end-of year balances.

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

additional information

publications and other news sources

Additional information relating to Chevron is contained in its *2018 Annual Report* to stockholders and its *Annual Report on Form 10-K* for the fiscal year ended December 31, 2018, filed with the U.S. Securities and Exchange Commission. Copies of these reports are available on the company's website, www.chevron.com, or may be requested by writing to:

Chevron Corporation
Investor Relations
6001 Bollinger Canyon Road, A3140
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

The *2018 Corporate Responsibility Report* is scheduled to be available in May 2019 on the company's website, www.chevron.com, or may be requested by writing to:

Chevron Corporation
Corporate Affairs
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 and the Proxy Statement.

legal notice

As used in this report, the terms "Chevron," "the company" and "its" may refer to Chevron Corporation, one or more of its consolidated subsidiaries, or to all of them taken as a whole, but unless the context clearly indicates otherwise, the term should not be read to include "affiliates" of Chevron, that is, those companies accounted for by the equity method (generally owned 50 percent or less) or investments accounted for by the non-equity method. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

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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 2018 Supplement to the 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," "will," "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 the company's control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets or shares or the delay or failure of such transactions to close based on required closing conditions; the potential for gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, tariffs, sanctions, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; material reductions in corporate liquidity and access to debt markets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; the company's ability to identify and mitigate the risks and hazards inherent in operating in the global energy industry; and the factors set forth under the heading "Risk Factors" on pages 18 through 21 on the company's *2018 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.

Certain terms, such as "unrisked resources," "unrisked resource base," "recoverable resources" and "original oil in place," among others, may be used in this report to describe certain aspects of the company's portfolio and oil and gas properties beyond the proved reserves. For definitions of, and further information regarding, these and other terms, see the "glossary of energy and financial terms" on pages 54 and 55 of this report.

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

This publication was issued in March 2019 solely for the purpose of providing additional Chevron financial and statistical data. It is not a circular or prospectus regarding any security or stock of the company, nor is it issued in connection with any sale, offer for sale of or solicitation of any offer to buy any securities. This report supplements the *Chevron Corporation 2018 Annual Report* to stockholders and should be read in conjunction with it. The financial information contained in this *2018 Supplement to the Annual Report* is expressly qualified by reference to the *2018 Annual Report*, which contains audited financial statements, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and other supplemental data.

chevron history

1879
Incorporated in San Francisco, California, as the Pacific Coast Oil Company.

1900
Acquired by the West Coast operations of John D. Rockefeller's original Standard Oil Company.

1911
Emerged as an autonomous entity – Standard Oil Company (California) – following U.S. Supreme Court decision to divide the Standard Oil conglomerate into 34 independent companies.

1926
Acquired Pacific Oil Company to become Standard Oil Company of California (Socal).

1936
Formed the Caltex Group of Companies, jointly owned by Socal and The Texas Company (later became Texaco), to combine Socal's exploration and production interests in the Middle East and Indonesia and provide an outlet for crude oil through The Texas Company's marketing network in Africa and Asia.

1947
Acquired Signal Oil Company, obtaining the Signal brand name and adding 2,000 retail stations in the western United States.

1961
Acquired Standard Oil Company (Kentucky), a major petroleum products marketer in five southeastern states, to provide outlets for crude oil from southern Louisiana and the U.S. Gulf of Mexico, where the company was a major producer.

1984
Acquired Gulf Corporation – nearly doubling the company's crude oil and natural gas activities – and gained a significant presence in industrial chemicals, natural gas liquids and coal. Changed name to Chevron Corporation to identify with the name under which most products were marketed.

1988
Purchased Tenneco Inc.'s U.S. Gulf of Mexico crude oil and natural gas properties, becoming one of the largest U.S. natural gas producers.

1993
Formed Tengizchevroil, a joint venture with the Republic of Kazakhstan, to develop and produce the giant Tengiz Field, becoming the first major Western oil company to enter newly independent Kazakhstan.

1999
Acquired Rutherford-Moran Oil Corporation. This acquisition provided inroads to Asian natural gas markets.

2001
Merged with Texaco Inc. and changed name to ChevronTexaco Corporation. Became the second-largest U.S.-based energy company.

2002
Relocated corporate headquarters from San Francisco, California, to San Ramon, California.

2005
Acquired Unocal Corporation, an independent crude oil and natural gas exploration and production company. Unocal's upstream assets bolstered Chevron's already-strong position in the Asia-Pacific, U.S. Gulf of Mexico and Caspian regions. Changed name to Chevron Corporation to convey a clearer, stronger and more unified presence in the global marketplace.

2011
Acquired Atlas Energy, Inc., an independent U.S. developer and producer of shale gas resources. The acquired assets provided a targeted, high-quality core acreage position, primarily in the Marcellus Shale.

Chevron Corporation
6001 Bollinger Canyon Road, San Ramon, CA 94583-2324 USA
www.chevron.com

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