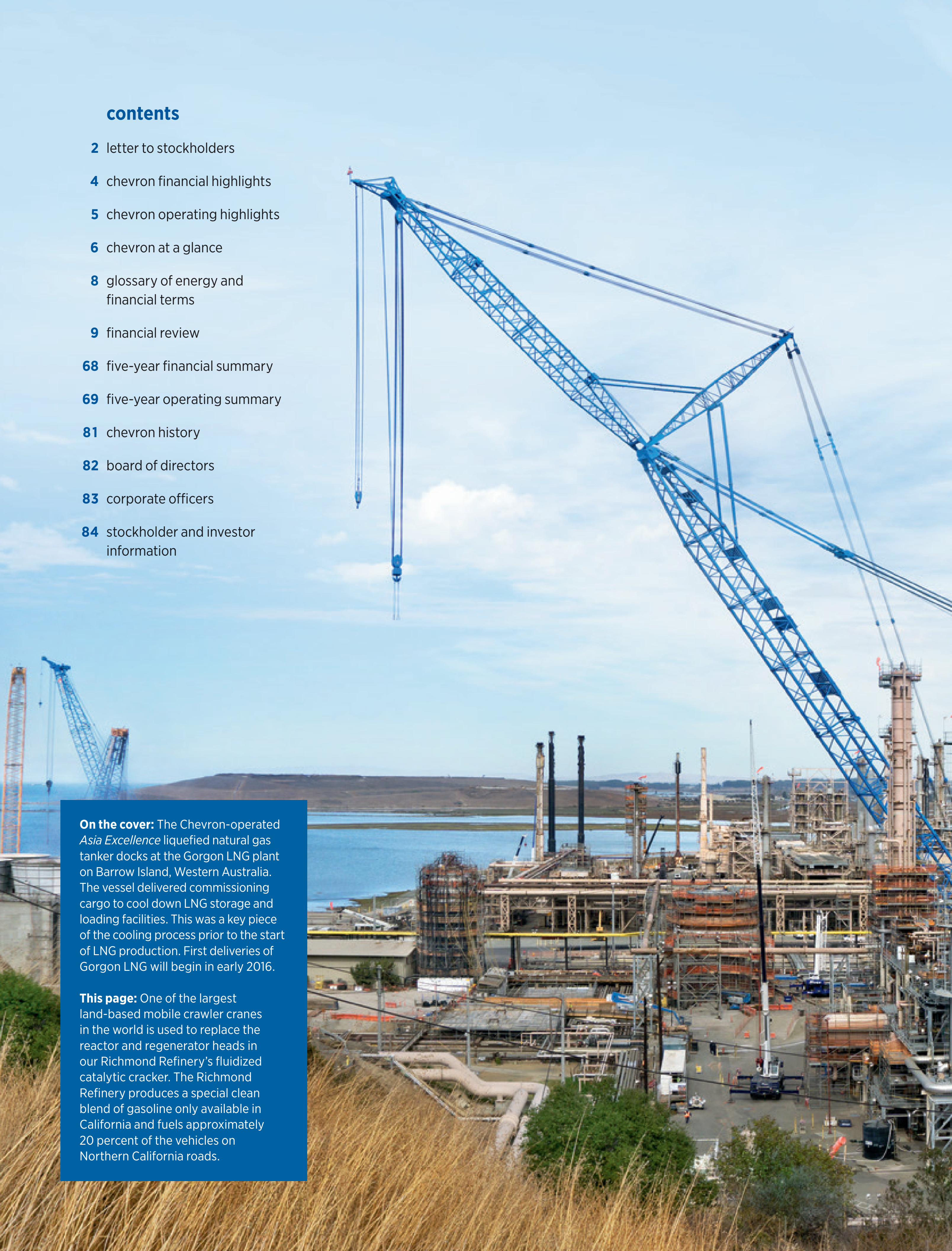
Chevron

2015 annual report

human energy®

contents



On the cover: The Chevron-operated *Asia Excellence* liquefied natural gas tanker docks at the Gorgon LNG plant on Barrow Island, Western Australia. The vessel delivered commissioning cargo to cool down LNG storage and loading facilities. This was a key piece of the cooling process prior to the start of LNG production. First deliveries of Gorgon LNG will begin in early 2016.

This page: One of the largest land-based mobile crawler cranes in the world is used to replace the reactor and regenerator heads in our Richmond Refinery's fluidized catalytic cracker. The Richmond Refinery produces a special clean blend of gasoline only available in California and fuels approximately 20 percent of the vehicles on Northern California roads.

2015 brought a steep and dramatic drop in the price of crude oil, one of the largest declines our industry has experienced in years. Chevron's response was to reduce capital spending and aggressively cut costs while moving forward on developments that will grow production and cash flow for the future. We are focused on improving project execution and delivering results safely, reliably, on time and within budget. We are optimizing our portfolio by divesting assets that no longer have a strategic fit or cannot compete for capital with other investment alternatives. And we are capturing the benefits of being a fully integrated energy company with Downstream and Chemicals delivering strong results. We are optimistic about the future and committed to being a top competitor in any economic environment.

The online version of this report contains additional information about our company, as well as videos of our various projects. We invite you to visit our website at **Chevron.com/AnnualReport2015**.

to our stockholders

Low commodity prices made 2015 a challenging year for Chevron and the entire oil and natural gas industry, reducing earnings across the sector.

Our full-year 2015 net income was $4.6 billion, down from $19.2 billion in 2014. Our sales and other operating revenue were $129.9 billion, down from $200.5 billion in 2014. We achieved a 2.5 percent return on capital employed versus the 10.9 percent achieved in 2014.

In light of difficult market conditions, we took significant actions to reduce costs and improve net cash flow. We reduced capital and operating expenses by $9 billion through renegotiating contracts with vendors and suppliers, streamlining organizations to reduce our employee and contractor workforce, deferring and canceling projects not economic at low prices, and selling $6 billion in nonstrategic and other assets.

We had a number of notable accomplishments during 2015. Our Upstream business, which is responsible for exploration and production, increased worldwide net oil-equivalent production by 2 percent, to 2.6 million barrels per day. We started up the Lianzi Field, located in a unitized offshore zone between the Republic of Congo and Angola; Moho Nord, our deepwater development offshore the Republic of Congo; Agbami 3, off the coast of the central Niger Delta region; and Chuandongbei, our natural gas field in southwest China, which initiated production in early 2016. In addition we ramped up Jack/St. Malo and Tubular Bells in the U.S. Gulf of Mexico. Also significant progress was achieved on our major capital projects, including Gorgon, our largest Australian liquefied natural gas (LNG) project, and Wheatstone LNG as they move toward start-up in 2016 and mid-2017, respectively.

We added approximately 1 billion barrels of net oil-equivalent proved reserves in 2015. These additions equate to approximately 107 percent of net oil-equivalent production for the year. Significant reserves were added from the Permian Basin in the United States and the Wheatstone Project in Australia. In our exploration program, we successfully drilled an appraisal well of our Anchor discovery in the deepwater Gulf of Mexico.

Our Downstream and Chemicals business, which is responsible for our refining, marketing and chemical manufacturing, had an outstanding year. This business maintained reliable operations, benefited from lower feedstock costs and realized efficiencies gained by the reshaping of our portfolio in recent years.

"Our company's products provide the energy that is critical for economic progress. We are well positioned to meet growing demand in a safe and responsible manner."

2015 was one of our best years in overall health, environment and safety performance and our best year ever in preventing significant incidents. Our Days Away From Work Rate and Motor Vehicle Crash Rate set new record lows, and our Total Recordable Incident Rate and petroleum spill volume matched last year's record lows.

We also continued our support of the communities in which we work. This past year we advanced our strategic programs and partnerships, with more than $233 million in global social investments. We focused these investments in three core areas — health, education and economic development — to improve access to health care, develop skilled workers, and boost local and regional economies. These social investments complement our investments in projects and local goods and services, creating jobs and generating revenues for the communities where we operate. More details are available in the *2015 Corporate Responsibility Report*.

I am proud to note that 2015 marked the 28th consecutive year that we increased the annual per-share dividend payout. Our top financial priority remains maintaining and growing the dividend as the pattern of earnings, cash flow and balance sheet strength permits. Our year-end debt ratio was a comfortable 20.2 percent.

Looking ahead, we announced a 2016 capital and exploratory budget of $26.6 billion, which is 22 percent lower than our expenditures for 2015 and 34 percent lower than 2014. This capital budget will enable us to complete and ramp up projects under construction, fund high-return, short-cycle investments, preserve options for viable long-cycle projects, and ensure safe, reliable operations.

The focus of the enterprise in 2016 will remain on our five key priorities — safely starting up projects under construction and realizing the cash flow from them, lowering capital spending, reducing operating expenses, completing our divestment program for assets that have greater value to others than to us, and doing all this while continuing to operate safely and reliably.

Our company's products provide the energy that is critical for economic progress. We are well positioned to meet growing demand in a safe and responsible manner.

In all we do, we are guided by The Chevron Way. This roadmap underpins the character of our company and establishes the values by which we deliver our results. I am confident that our company and our employees have what it takes to meet the challenges of the current business environment and achieve our vision of being *the* global energy company most admired for its people, partnership and performance.

Thank you for your confidence and your investment in Chevron.

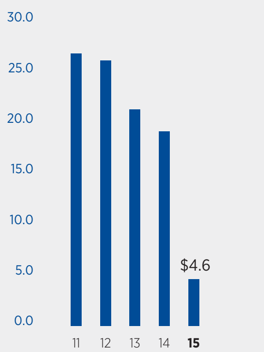
John S. Watson
Chairman of the Board and
Chief Executive Officer
February 25, 2016

chevron financial highlights

Millions of dollars, except per-share amounts	**2015**	2014	% Change
Net income attributable to Chevron Corporation	**$ 4,587**	$ 19,241	(76.2)%
Sales and other operating revenues	**$ 129,925**	$ 200,494	(35.2)%
Noncontrolling interests income	**$ 123**	$ 69	78.3 %
Interest expense (after tax)	**$ —**	$ —	0.0 %
Capital and exploratory expenditures*	**$ 33,979**	$ 40,316	(15.7)%
Total assets at year-end	**$ 266,103**	$ 266,026	0.0 %
Total debt and capital lease obligations at year-end	**$ 38,592**	$ 27,818	38.7 %
Noncontrolling interests	**$ 1,170**	$ 1,163	0.6 %
Chevron Corporation stockholders' equity at year-end	**$ 152,716**	$ 155,028	(1.5)%
Cash provided by operating activities	**$ 19,456**	$ 31,475	(38.2)%
Common shares outstanding at year-end (Thousands)	**1,868,646**	1,865,481	0.2 %
Per-share data			
Net income attributable to Chevron Corporation — diluted	**$ 2.45**	$ 10.14	(75.8)%
Cash dividends	**$ 4.28**	$ 4.21	1.7 %
Chevron Corporation stockholders' equity	**$ 81.73**	$ 83.10	(1.7)%
Common stock price at year-end	**$ 89.96**	$ 112.18	(19.8)%
Total debt to total debt-plus-equity ratio	**20.2%**	15.2%	
Return on average Chevron Corporation stockholders' equity	**3.0%**	12.7%	
Return on capital employed (ROCE)	**2.5%**	10.9%	

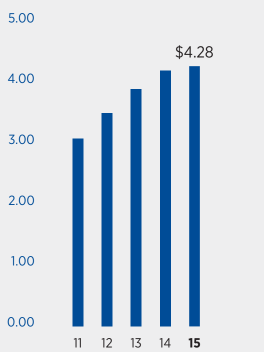
* Includes equity in affiliates

Net income attributable to Chevron Corporation
Billions of dollars



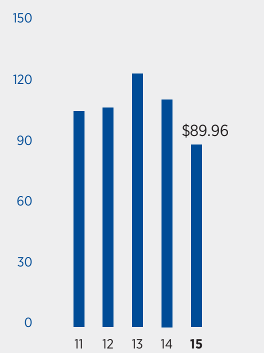
The decrease in 2015 was due to lower earnings in upstream as a result of lower crude oil margins and higher depreciation expense, partially offset by higher earnings in downstream.

Annual cash dividends
Dollars per share



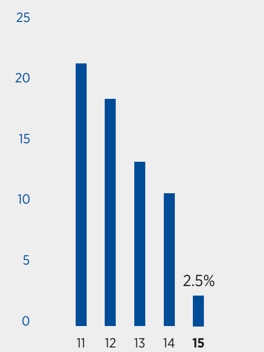
The company's annual dividend increased for the 28th consecutive year.

Chevron year-end common stock price
Dollars per share



The company's stock price declined 19.8 percent in 2015.

Return on capital employed
Percent



Chevron's return on capital employed declined to 2.5 percent on lower earnings and higher capital employed.

chevron operating highlights[1]

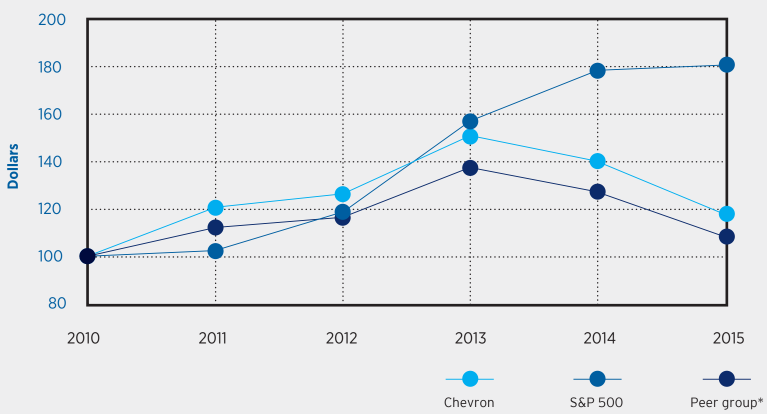
	2015	2014	% Change
Net production of crude oil, condensate and natural gas liquids (Thousands of barrels per day)	**1,744**	1,709	2.0 %
Net production of natural gas (Millions of cubic feet per day)	**5,269**	5,167	2.0 %
Total net oil-equivalent production (Thousands of oil-equivalent barrels per day)	**2,622**	2,571	2.0 %
Refinery input (Thousands of barrels per day)	**1,702**	1,690	0.7 %
Sales of refined products (Thousands of barrels per day)	**2,735**	2,711	0.9 %
Net proved reserves of crude oil, condensate and natural gas liquids[2] (Millions of barrels)			
Consolidated companies	**4,262**	4,285	(0.5)%
Affiliated companies	**2,000**	1,964	1.8 %
Net proved reserves of natural gas[2] (Billions of cubic feet)			
Consolidated companies	**25,946**	25,707	0.9 %
Affiliated companies	**3,491**	3,409	2.4 %
Net proved oil-equivalent reserves[2] (Millions of barrels)			
Consolidated companies	**8,586**	8,570	0.2 %
Affiliated companies	**2,582**	2,532	2.0 %
Number of employees at year-end[3]	**58,178**	61,456	(5.3)%

[1] Includes equity in affiliates, except number of employees
[2] At the end of the year
[3] Excludes service station personnel

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, 2010, and ending December 31, 2015, and for the peer group is weighted by market capitalization as of the beginning of each year. It includes the reinvestment of all dividends that an investor would be entitled to receive and is adjusted for stock splits. The interim measurement points show the value of $100 invested on December 31, 2010, as of the end of each year between 2011 and 2015.

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



	2010	2011	2012	2013	2014	2015
Chevron	**100.00**	**120.27**	**126.28**	**150.58**	**140.17**	**117.78**
S&P 500	100.00	102.12	118.44	156.83	178.30	180.81
Peer group*	100.00	112.01	116.15	137.36	127.21	108.23

*Peer Group: BP p.l.c.-ADS, ExxonMobil, Royal Dutch Shell p.l.c.-ADS, Total S.A.-ADS

chevron at a glance

Chevron is one of the world's leading integrated energy companies. 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. We are involved in virtually every facet of the energy industry. 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; generate power and produce geothermal energy; and develop and deploy technologies that enhance business value in every aspect of the company's operations.

Photo: With the Jack/St. Malo development, Chevron continues to advance the boundaries of deepwater exploration and production. The Jack and St. Malo fields are among the largest in the U.S. Gulf of Mexico and are expected to have a producing life of more than 30 years. In 2015 Chevron ramped up production from Jack/St. Malo and announced two other important discoveries in the region: Anchor and Sicily.

Upstream	**Strategy:** Grow profitably in core areas and build new legacy positions.	Upstream explores for and produces crude oil and natural gas. At the end of 2015 worldwide net oil-equivalent proved reserves for consolidated and affiliated companies were 11.2 billion barrels. During 2015 net oil-equivalent production averaged 2.6 million barrels per day. Top producing areas include the United States, Kazakhstan, Nigeria, Thailand, Indonesia, Bangladesh, Angola, Australia, Canada and Venezuela. Major conventional exploration areas include the deepwater U.S. Gulf of Mexico, offshore northwestern Australia and the deepwater regions of western Africa. Key exploration areas for unconventional shale and tight resources are the United States, Canada and Argentina.
Downstream and Chemicals	**Strategy:** Deliver competitive returns and grow earnings across the value chain.	Downstream and Chemicals includes refining, fuels and lubricants marketing, and petrochemicals and additives manufacturing and marketing. In 2015 we processed 1.7 million barrels of crude oil per day and averaged 2.7 million barrels per day of refined product sales worldwide. Our most significant areas of refinery operations are the west coast of North America, the U.S. Gulf Coast, Singapore, Thailand, South Korea and South Africa. We hold interests in 11 refineries, are a leader in the manufacturing and sale of premium base oils, and market transportation fuels and lubricants under the Chevron, Texaco and Caltex brands. Products are sold through a network of 13,946 retail stations, including those of affiliated companies. Our chemicals business includes Chevron Phillips Chemical Company LLC, a 50 percent-owned affiliate that is one of the world's leading manufacturers of commodity petrochemicals, and Chevron Oronite Company LLC, which develops, manufactures and markets quality additives that improve the performance of fuels and lubricants.
Midstream and Development	**Strategy:** Apply commercial and functional excellence to enable the success of Upstream and Downstream and Chemicals.	Midstream and Development provides services that link Upstream and Downstream and Chemicals to the market. This includes commercializing our equity gas resource base; maximizing the value of the company's equity natural gas, crude oil, natural gas liquids and refined products; and transporting products worldwide. Midstream and Development has global operations with major centers in Houston; London; Singapore; and San Ramon, California.
Technology	**Strategy:** Differentiate performance through technology.	Our three technology companies — Chevron Energy Technology, Chevron Technology Ventures and Chevron Information Technology — are focused on enhancing business value in all aspects of our operations. We have established technology centers in Australia, the United Kingdom and the United States. Together they provide strategic research, technology development, technical and computing infrastructure services, and data protection to our global businesses.
Renewable Energy and Energy Efficiency	**Strategy:** Invest in profitable renewable energy and energy efficiency solutions.	We are one of the world's leading producers of geothermal energy, supplying abundant, reliable energy to millions of people in Indonesia and the Philippines. We also are investing in energy efficiency technologies to improve the performance of our operations worldwide.
Operational Excellence		We define operational excellence as the systematic management of process safety, personal safety and health, the environment, operational reliability, and energy efficiency. We are committed to attaining superior performance in operational excellence and believe our safety goal of zero incidents is attainable.

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 spend 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 also may 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.

Renewables Energy resources that are not depleted when consumed or converted into other forms of energy (e.g., solar, geothermal, ocean and tide, wind, hydroelectric power, biofuels and hydrogen).

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, 2015.

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.

financial terms

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

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

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

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

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

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

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

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," "may," "could," "should," "budgets," "outlook," "on schedule," "on track" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company's control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; the company's ability to realize anticipated cost savings and expenditure reductions; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of the company's suppliers, vendors, partners and equity affiliates, particularly during extended periods of low prices for crude oil and natural gas; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's operations due to war, accidents, political events, civil unrest, severe weather, cyber threats and terrorist acts, crude oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries, or other natural or human causes beyond its control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; material reductions in corporate liquidity and access to debt markets; the 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 21 through 23 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	**2015**	2014	2013
Net Income Attributable to Chevron Corporation	**$ 4,587**	$ 19,241	$ 21,423
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
– Basic	**$ 2.46**	$ 10.21	$ 11.18
– Diluted	**$ 2.45**	$ 10.14	$ 11.09
Dividends	**$ 4.28**	$ 4.21	$ 3.90
Sales and Other Operating Revenues	**$ 129,925**	$ 200,494	$ 220,156
Return on:			
Capital Employed	**2.5%**	10.9%	13.5%
Stockholders' Equity	**3.0%**	12.7%	15.0%

Earnings by Major Operating Area

Millions of dollars	**2015**	2014	2013
Upstream			
United States	**$ (4,055)**	$ 3,327	$ 4,044
International	**2,094**	13,566	16,765
Total Upstream	**(1,961)**	16,893	20,809
Downstream			
United States	**3,182**	2,637	787
International	**4,419**	1,699	1,450
Total Downstream	**7,601**	4,336	2,237
All Other	**(1,053)**	(1,988)	(1,623)
Net Income Attributable to Chevron Corporation[1,2]	**$ 4,587**	$ 19,241	$ 21,423
[1] Includes foreign currency effects:	**$ 769**	$ 487	$ 474

[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 14 for a discussion of financial results by major operating area for the three years ended December 31, 2015.

Business Environment and Outlook

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

Earnings of the company depend mostly on the profitability of its upstream business segment. The biggest factor affecting the results of operations for the upstream segment is the price of crude oil. The price of crude oil has fallen significantly since mid-year 2014, reflecting persistently high global crude oil inventories and production. The downturn in the price of crude oil has impacted, and, depending upon its duration, will continue to significantly impact the company's results of operations, cash flows, leverage, capital and exploratory investment program and production outlook. The company is responding with reductions in operating expenses, including employee reductions, reductions in capital and exploratory expenditures in 2016 and future periods, and increased asset sales. The company anticipates that crude oil prices will increase in the future, as continued growth in demand and a slowing in supply growth should bring global markets into balance; however, the timing of any such increase is unknown. In the company's downstream business, crude oil is the largest cost component of refined products.

Refer to the "Cautionary Statement Relevant to Forward-Looking Information" on page 9 and to "Risk Factors" in Part I, Item 1A, on pages 21 through 23 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 growth. Refer to the "Results of Operations" section beginning on page 14 for discussions of net gains on asset sales during 2015. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

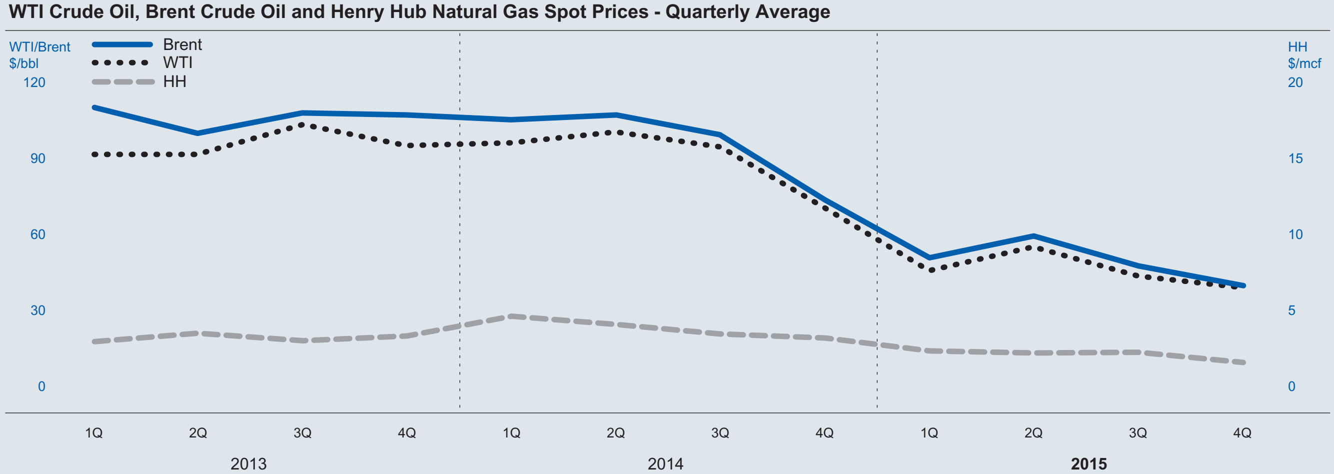
The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of movements in prices for crude oil and natural gas. Management takes these developments into account in the conduct of daily operations and for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

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

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

The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. However, price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can be subject to external factors beyond the company's control including, among other things, the general level of inflation, commodity prices and prices charged by the industry's material and service providers, which can be affected by the volatility of the industry's own supply-and-demand conditions for such materials and services. In recent years, Chevron and the oil and gas industry generally experienced an increase in certain costs that exceeded the general trend of inflation in many areas of the world. As a result of the decline in prices of crude oil and other commodities since mid-2014, these cost pressures have softened. Capital and exploratory expenditures and operating expenses can also be affected by damage to production facilities caused by severe weather or civil unrest, delays in construction, or other factors.

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



The chart above shows the trend in benchmark prices for Brent crude oil, West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. The Brent price averaged $52 per barrel for the full-year 2015, compared to $99 in 2014. As of mid-February 2016, the Brent price was $31 per barrel. The majority of the company's equity crude production is priced based on the Brent benchmark. Prices firmed in the first half of 2015, but declined in the remainder of the year amid persistently high global crude oil inventories and production.

The WTI price averaged $49 per barrel for the full-year 2015, compared to $93 in 2014. As of mid-February 2016, the WTI price was $29 per barrel. WTI traded at a discount to Brent throughout 2015 due to high inventories and excess crude supply in the U.S. market. With the lifting of the U.S. crude oil export ban in December 2015, the spread between WTI and Brent narrowed substantially and WTI traded around parity into February 2016.

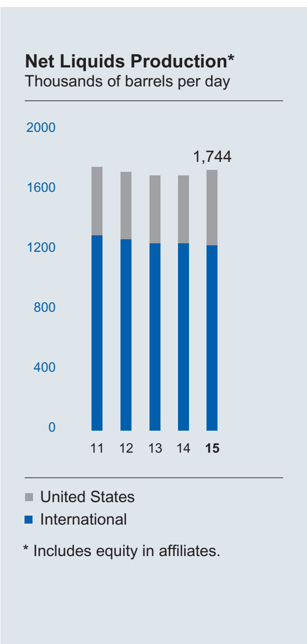
A differential in crude oil prices exists between high-quality (high-gravity, low-sulfur) crudes and those of lower quality (low-gravity, high-sulfur). The amount of the differential in any period is associated with the relative supply/demand balances for each crude type, which are functions of the capacity of refineries that are able to process each as feedstock into high-value light products (motor gasoline, jet fuel, aviation gasoline and diesel fuel). In second-half 2015, the differential expanded in North America as Canadian heavy crude production recovered from earlier planned and unplanned outages, while light sweet crude prices in the U.S. were supported by reductions in the rig count and slowing domestic production growth. Outside of North

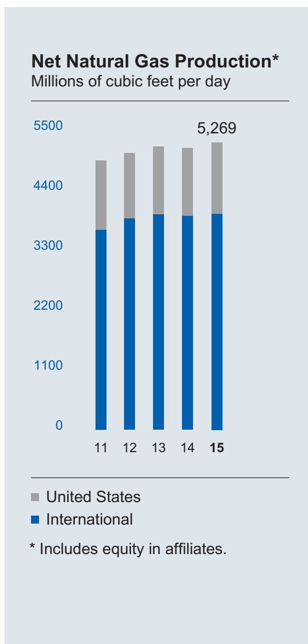
America, high refinery runs in Europe and Asia supported pricing for light sweet crude from the Atlantic Basin, while increased output from Iraq and other Middle East producers pressured values of heavier, more sour crudes.

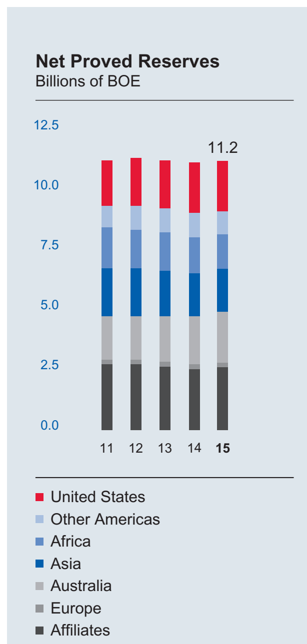
Chevron produces or shares in the production of heavy crude oil in California, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page 19 for the company's average U.S. and international crude oil realizations.)

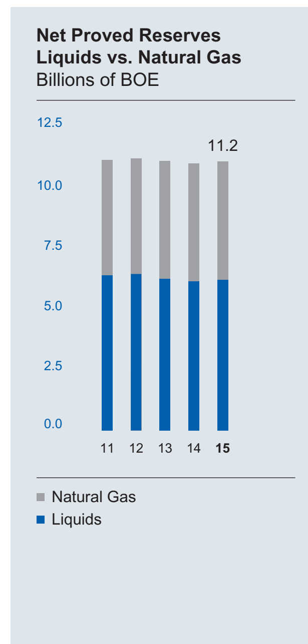
In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged $2.62 per thousand cubic feet (MCF) during 2015, compared with $4.28 during 2014. As of mid-February 2016, the Henry Hub spot price was $1.92 per MCF.

Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. Chevron sells natural gas into the domestic pipeline market in most locations. In some locations, Chevron is investing in long-term projects to install infrastructure 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. Approximately 85 percent of the equity LNG offtake from the operated Australian LNG projects is targeted to be sold into binding long-term contracts, with the remainder to be sold in the Asian spot LNG market. The Asian spot market reflects the supply and demand for LNG in the Pacific Basin and is not directly linked to crude oil prices. International natural gas realizations averaged $4.53 per MCF during 2015, compared with $5.78 per MCF during 2014. (See page 19 for the company's average natural gas realizations for the U.S. and international regions.)









The company's worldwide net oil-equivalent production in 2015 averaged 2.622 million barrels per day. About one-fifth of the company's net oil-equivalent production in 2015 occurred in the OPEC-member countries of Angola, Nigeria, Venezuela and the Partitioned Zone between Saudi Arabia and Kuwait. OPEC quotas had no effect on the company's net crude oil production in 2015 or 2014. At their December 2015 meeting, members of OPEC did not agree on a target production level, and in January 2016 western sanctions on Iran were lifted. As such, OPEC output is now considered likely to increase from recent levels of approximately 31.5 million barrels per day as Iranian production and exports recover.

The company estimates that net oil-equivalent production in 2016 will be flat to 4 percent growth compared to 2015. This estimate is subject to many factors and uncertainties, including the duration of the low price environment that began in second-half 2014; quotas or other actions that may be imposed by OPEC; price effects on entitlement volumes; changes in fiscal terms or restrictions on the scope of company operations; delays in construction, start-up or ramp-up of projects; fluctuations in demand for natural gas in various markets; weather conditions that may shut in production; civil unrest; changing geopolitics; delays in completion of maintenance turnarounds; greater-than-expected declines in production from mature fields; or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and, for new, large-scale projects, the time lag between initial exploration and the beginning of production. Investments in upstream projects generally begin well in advance of the start of the associated crude oil and natural gas production. A significant majority of Chevron's upstream investment is made outside the United States.

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 2016, 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 2015 were not significant and are not expected to be significant in 2016.

Net proved reserves for consolidated companies and affiliated companies totaled 11.2 billion barrels of oil-equivalent at year-end 2015, an increase of 1 percent from year-end 2014. The reserve replacement ratio in 2015 was 107 percent. Refer to Table V beginning on page 74 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2013 and each year-end from 2013 through 2015, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2015.

Refer to the "Results of Operations" section on pages 14 through 16 for additional discussion of the company's upstream business.

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

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

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

Refer to the "Results of Operations" section on pages 14 through 16 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 2015 and early 2016 included the following:

Upstream

Angola-Republic of Congo Joint Development Area Achieved first production from the Lianzi Project.

Australia Progressed LNG Train 1 commissioning and start-up activities for the Gorgon Project, with first cargo lifting expected in March 2016. All Train 2 modules are installed, and all remaining Train 3 modules were delivered as of January 2016.

Progressed construction of the Wheatstone Project. Major milestones reached include the installation of the offshore platform and topsides, and all of the subsea pipelines and structures, along with the delivery of all LNG Train 1 and common modules.

Announced a natural gas discovery, Isosceles, in the Carnarvon Basin in 50 percent-owned Block WA-392-P.

Bangladesh Achieved first liquids from the Bibiyana Expansion Liquid Recovery Unit.

China Achieved first production from the Chuandongbei Project in early 2016.

Republic of Congo Announced start of production from the first phase of the Moho Nord Project.

United States Announced a successful appraisal well at the Anchor prospect in the deepwater Gulf of Mexico.

Downstream

Australia Completed the sale of the company's 50 percent interest in Caltex Australia Limited.

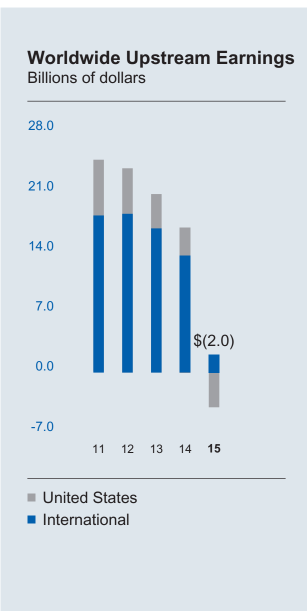
New Zealand Completed the sale of the company's interest in The New Zealand Refining Company Limited and reached agreement to sell the company's marketing operations.

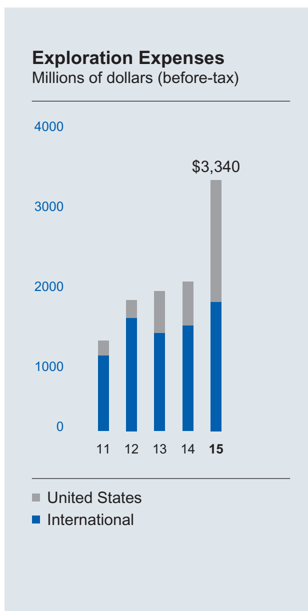
Other

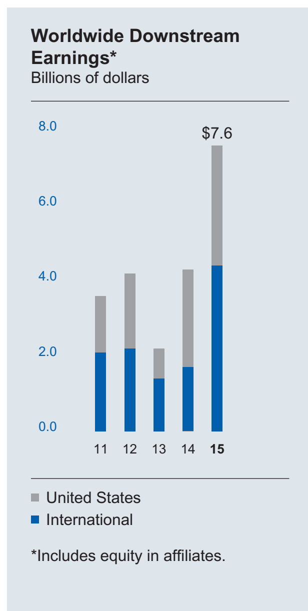
Common Stock Dividends The 2015 annual dividend was $4.28 per share, making 2015 the 28th consecutive year that the company increased its annual dividend payout.

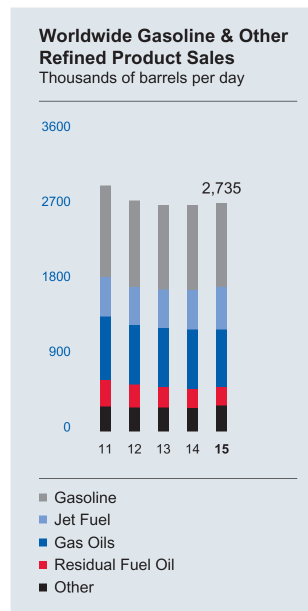
Results of Operations

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 14, beginning on page 45, 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 10 through 13.









U.S. Upstream

Millions of dollars	**2015**	2014	2013
Earnings	**$ (4,055)**	$ 3,327	$ 4,044

U.S. upstream operations incurred a loss of $4.06 billion in 2015 compared to earnings of $3.33 billion from 2014. The decrease was primarily due to lower crude oil and natural gas realizations of $4.86 billion and $570 million, respectively, higher depreciation expenses of $2.19 billion and higher exploration expenses of $650 million. The increase in depreciation and exploration expenses was primarily due to impairments and project cancellations. Lower gains on asset sales also contributed to the decrease with current year gains of $110 million compared with $700 million in 2014. Partially offsetting these effects were higher crude oil production of $900 million and lower operating expenses of $450 million.

U.S. upstream earnings of $3.33 billion in 2014 decreased $717 million from 2013, primarily due to lower crude oil prices of $950 million. Higher depreciation expenses of $440 million and higher operating expenses of $210 million also contributed to the decline. Partially offsetting the decrease were gains on asset sales of $700 million in 2014 compared with $60 million in 2013, higher natural gas realizations of $150 million and higher crude oil production of $100 million.

The company's average realization for U.S. crude oil and natural gas liquids in 2015 was $42.70 per barrel, compared with $84.13 in 2014 and $93.46 in 2013. The average natural gas realization was $1.92 per thousand cubic feet in 2015, compared with $3.90 in 2014 and $3.37 in 2013.

Net oil-equivalent production in 2015 averaged 720,000 barrels per day, up 8 percent from 2014 and 10 percent from 2013. Between 2015 and 2014, production increases due to project ramp-ups in the Gulf of Mexico and the Permian Basin in Texas and New Mexico were partially offset by the effect of asset sales and normal field declines. Between 2014 and 2013, production increases in the Permian Basin in Texas and New Mexico and the Marcellus Shale in western Pennsylvania were partially offset by normal field declines.

The net liquids component of oil-equivalent production for 2015 averaged 501,000 barrels per day, up 10 percent from 2014 and 12 percent from 2013. Net natural gas production averaged about 1.3 billion cubic feet per day in 2015, up 5 percent from 2014 and 2013. Refer to the "Selected Operating Data" table on page 19 for a three-year comparison of production volumes in the United States.

International Upstream

Millions of dollars		**2015**		2014		2013
Earnings*	**$**	**2,094**	$	13,566	$	16,765
*Includes foreign currency effects:	**$**	**725**	$	597	$	559

International upstream earnings were $2.09 billion in 2015 compared with $13.57 billion in 2014. The decrease between periods was primarily due to lower crude oil and natural gas realizations of $10.57 billion and $880 million, respectively, and higher depreciation expenses of $1.11 billion, primarily reflecting impairments. Lower gains on asset sales also contributed to the decrease with current year gains of $370 million compared with $1.10 billion in 2014. Partially offsetting the decrease were higher crude oil sales volumes of $590 million and lower operating expenses of $510 million. Foreign currency effects increased earnings by $725 million in 2015, compared with an increase of $597 million a year earlier.

International upstream earnings were $13.57 billion in 2014 compared with $16.77 billion in 2013. The decrease between periods was primarily due to lower crude oil prices and sales volumes of $1.97 billion and $400 million, respectively. Also contributing to the decrease were higher depreciation expenses of $1.02 billion, mainly related to impairments and other asset write-offs, and higher operating and tax expenses of $340 million and $310 million, respectively. Partially offsetting these items were gains on asset sales of $1.10 billion in 2014, compared with $140 million in 2013. Foreign currency effects increased earnings by $597 million in 2014, compared with a decrease of $559 million a year earlier.

The company's average realization for international crude oil and natural gas liquids in 2015 was $46.52 per barrel, compared with $90.42 in 2014 and $100.26 in 2013. The average natural gas realization was $4.53 per thousand cubic feet in 2015, compared with $5.78 and $5.91 in 2014 and 2013, respectively.

International net oil-equivalent production was 1.90 million barrels per day in 2015, essentially unchanged from 2014 and down 2 percent from 2013. Between 2015 and 2014, production increases from entitlement effects in several locations and project ramp-ups in Bangladesh and other areas were offset by the Partitioned Zone shut-in, normal field declines and the effect of asset sales. Between 2014 and 2013, production increases due to project ramp-ups in Nigeria, Argentina and Brazil were more than offset by normal field declines, production entitlement effects in several locations and the effect of asset sales.

The net liquids component of international oil-equivalent production was 1.24 million barrels per day in 2015, a decrease of approximately 1 percent from 2014 and a decrease of approximately 3 percent from 2013. International net natural gas production of 4.0 billion cubic feet per day in 2015 was up 1 percent from 2014 and unchanged from 2013.

Refer to the "Selected Operating Data" table, on page 19, for a three-year comparison of international production volumes.

U.S. Downstream

Millions of dollars	**2015**	2014	2013
Earnings	**$ 3,182**	$ 2,637	$ 787

U.S. downstream operations earned $3.18 billion in 2015, compared with $2.64 billion in 2014. The increase was due to higher margins on refined product sales of $1.51 billion, partially offset by the absence of 2014 asset sale gains of $960 million.

U.S. downstream operations earned $2.64 billion in 2014, compared with $787 million in 2013. The increase in earnings was mainly due to higher margins on refined product sales of $830 million. Gains from asset sales were $960 million in 2014, compared with $250 million in 2013. Higher earnings from 50 percent-owned Chevron Phillips Chemical Company, LLC (CPChem) of $160 million and lower operating expenses of $80 million also contributed to the earnings increase.

Refined product sales of 1.23 million barrels per day in 2015 increased 1 percent, mainly reflecting higher sales of jet fuel. Sales volumes of refined products were 1.21 million barrels per day in 2014, an increase of 2 percent from 2013, mainly reflecting higher gas oil sales. U.S. branded gasoline sales of 522,000 barrels per day in 2015 increased 1 percent from 2014 and 2013.

Refer to the "Selected Operating Data" table on page 19 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

Millions of dollars	**2015**	2014	2013
Earnings*	**$ 4,419**	$ 1,699	$ 1,450
*Includes foreign currency effects:	**$ 47**	$ (112)	$ (76)

International downstream earned $4.42 billion in 2015, compared with $1.70 billion in 2014. The increase was primarily due to a $1.6 billion gain from the sale of the company's interest in Caltex Australia Limited in second quarter 2015 and higher margins on refined product sales of $690 million. Foreign currency effects increased earnings by $47 million in 2015, compared to a decrease of $112 million a year earlier.

International downstream earned $1.70 billion in 2014, compared with $1.45 billion in 2013. The increase was mainly due to a favorable change in the effects on derivative instruments of $640 million. The increase was partially offset by the economic buyout of a legacy pension obligation of $160 million in the 2014 period, lower margins on refined product sales of $130 million and higher tax expenses of $110 million. Foreign currency effects decreased earnings by $112 million in 2014, compared with a decrease of $76 million a year earlier.

Total refined product sales of 1.51 million barrels per day in 2015 were essentially unchanged from 2014. Excluding the effects of the Caltex Australia Limited divestment, refined product sales were up 107,000 barrels per day, primarily reflecting higher sales of jet fuel, gasoline and gas oil. Sales of 1.50 million barrels per day in 2014 declined 2 percent from 2013, mainly reflecting lower gas oil sales.

Refer to the "Selected Operating Data" table, on page 19, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars	**2015**	2014	2013
Net charges*	**$ (1,053)**	$ (1,988)	$ (1,623)
*Includes foreign currency effects:	**$ (3)**	$ 2	$ (9)

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 2015 decreased $935 million from 2014, mainly due to lower corporate tax items and the absence of 2014 charges related to mining assets, partially offset by higher charges related to reductions in corporate staffs. Net charges in 2014 increased $365 million from 2013, mainly due to higher environmental reserve additions, asset impairments and additional asset retirement obligations for mining assets, as well as higher corporate tax items. These increases were partially offset by the absence of 2013 impairments of power-related affiliates and lower other corporate charges.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2015**	2014	2013
Sales and other operating revenues	**$ 129,925**	$ 200,494	$ 220,156

Sales and other operating revenues decreased in 2015 primarily due to lower refined product and crude oil prices, partially offset by an increase in refined product and crude oil volumes. The decrease between 2014 and 2013 was mainly due to lower crude oil volumes, and lower refined product and crude oil prices.

Millions of dollars	**2015**	2014	2013
Income from equity affiliates	**$ 4,684**	$ 7,098	$ 7,527

Income from equity affiliates decreased in 2015 from 2014 mainly due to lower earnings from Tengizchevroil in Kazakhstan, CPChem, Angola LNG and the effect of the sale of Caltex Australia Limited in second quarter 2015. Partially offsetting these effects were higher earnings from GS Caltex in South Korea and Petropiar in Venezuela.

Income from equity affiliates decreased in 2014 from 2013 mainly due to lower upstream-related earnings from Tengizchevroil in Kazakhstan, Petropiar and Petroboscan in Venezuela, and Angola LNG. Partially offsetting these effects were higher downstream-related earnings from GS Caltex in South Korea, higher earnings from CPChem and the absence of 2013 impairments of power-related affiliates.

Refer to Note 15, beginning on page 48, for a discussion of Chevron's investments in affiliated companies.

Millions of dollars	**2015**	2014	2013
Other income	**$ 3,868**	$ 4,378	$ 1,165

Other income of $3.9 billion in 2015 included net gains from asset sales of $3.2 billion before-tax. Other income in 2014 and 2013 included net gains from asset sales of $3.6 billion and $710 million before-tax, respectively. Interest income was approximately $119 million in 2015, $145 million in 2014 and $136 million in 2013. Foreign currency effects increased other income by $82 million in 2015, $277 million in 2014 and $103 million in 2013.

Millions of dollars	**2015**	2014	2013
Purchased crude oil and products	**$ 69,751**	$ 119,671	$ 134,696

Crude oil and product purchases of $69.8 billion were down in 2015 mainly due to lower crude oil and refined product prices, partially offset by an increase in crude oil volumes. Crude oil and product purchases in 2014 decreased by $15.0 billion from the prior year, mainly due to lower crude oil and refined product prices, along with lower crude oil volumes.

Millions of dollars	**2015**	2014	2013
Operating, selling, general and administrative expenses	**$ 27,477**	$ 29,779	$ 29,137

Operating, selling, general and administrative expenses decreased $2.3 billion between 2015 and 2014. The decrease included lower fuel costs of $920 million. Also contributing to the decrease were lower expenses for construction, repair and maintenance of $300 million, contract labor of $270 million, and research, technical and professional services of $200 million.

Operating, selling, general and administrative expenses increased $642 million between 2014 and 2013. The increase included higher employee compensation and benefit costs of $360 million, primarily related to a buyout of a legacy pension obligation. Also contributing to the increase was higher transportation costs of $350 million, primarily reflecting the economic buyout of a long-term contractual obligation, and higher environmental expenses related to a mining asset of $300 million. Partially offsetting the increase were lower fuel expenses of $360 million.

Millions of dollars	**2015**	2014	2013
Exploration expense	**$ 3,340**	$ 1,985	$ 1,861

Exploration expenses in 2015 increased from 2014 mainly due to higher charges for well write-offs largely related to project cancellations. Exploration expenses in 2014 increased from 2013 mainly due to higher charges for well write-offs, partially offset by lower geological and geophysical expenses.

Millions of dollars		**2015**		2014		2013
Depreciation, depletion and amortization	**$**	**21,037**	$	16,793	$	14,186

Depreciation, depletion and amortization expenses increased in 2015 from 2014 mainly due to impairments of oil and gas producing fields of about $3.5 billion in 2015 compared with $900 million in 2014. Also contributing to the increase were higher depreciation rates and higher production levels for certain oil and gas producing fields. The increase in 2014 from 2013 was mainly due to higher depreciation rates and impairments for certain oil and gas producing fields, and the impairment of a mining asset.

Millions of dollars		**2015**		2014		2013
Taxes other than on income	**$**	**12,030**	$	12,540	$	13,063

Taxes other than on income decreased in 2015 from 2014 mainly due to lower crude oil and refined product prices. Taxes other than on income decreased in 2014 from 2013 primarily due to a decrease in duty expense in South Africa along with lower consumer excise taxes in Thailand, reflecting lower sales volumes at both locations.

Millions of dollars		**2015**		2014		2013
Income tax expense	**$**	**132**	$	11,892	$	14,308

Effective income tax rates were 3 percent in 2015, 38 percent in 2014 and 40 percent in 2013. The decrease in the effective tax rate between 2015 and 2014 primarily resulted from the impacts of jurisdictional mix, one-time tax benefits, foreign currency remeasurement, equity earnings and a reduction in statutory tax rates in the United Kingdom, partially offset by the effects of valuation allowances recognized on deferred tax assets and the sale of the company's interest in Caltex Australia Limited.

The rate decreased between 2014 and 2013 primarily due to the impact of changes in jurisdictional mix and equity earnings, and the tax effects related to the 2014 sale of interests in Chad and Cameroon, partially offset by other one-time and ongoing tax charges.

Selected Operating Data[1,2]

	2015	2014	2013
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**501**	456	449
Net Natural Gas Production (MMCFPD)[3]	**1,310**	1,250	1,246
Net Oil-Equivalent Production (MBOEPD)	**720**	664	657
Sales of Natural Gas (MMCFPD)	**3,913**	3,995	5,483
Sales of Natural Gas Liquids (MBPD)	**26**	20	17
Revenues From Net Production			
Liquids ($/Bbl)	**$ 42.70**	$ 84.13	$ 93.46
Natural Gas ($/MCF)	**$ 1.92**	$ 3.90	$ 3.37
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)[4]	**1,243**	1,253	1,282
Net Natural Gas Production (MMCFPD)[3]	**3,959**	3,917	3,946
Net Oil-Equivalent Production (MBOEPD)[4]	**1,902**	1,907	1,940
Sales of Natural Gas (MMCFPD)	**4,299**	4,304	4,251
Sales of Natural Gas Liquids (MBPD)	**24**	28	26
Revenues From Liftings			
Liquids ($/Bbl)	**$ 46.52**	$ 90.42	$ 100.26
Natural Gas ($/MCF)	**$ 4.53**	$ 5.78	$ 5.91
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD)[4]			
United States	**720**	664	657
International	**1,902**	1,907	1,940
Total	**2,622**	2,571	2,597
U.S. Downstream			
Gasoline Sales (MBPD)[5]	**621**	615	613
Other Refined Product Sales (MBPD)	**607**	595	569
Total Refined Product Sales (MBPD)	**1,228**	1,210	1,182
Sales of Natural Gas Liquids (MBPD)	**127**	121	125
Refinery Input (MBPD)	**924**	871	774
International Downstream			
Gasoline Sales (MBPD)[5]	**389**	403	398
Other Refined Product Sales (MBPD)	**1,118**	1,098	1,131
Total Refined Product Sales (MBPD)[6]	**1,507**	1,501	1,529
Sales of Natural Gas Liquids (MBPD)	**65**	58	62
Refinery Input (MBPD)[7]	**778**	819	864

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 oil.

3 Includes natural gas consumed in operations (MMCFPD):

	2015	2014	2013
United States	**66**	71	72
International	**430**	452	458

4 Includes net production of synthetic oil:

	2015	2014	2013
Canada	**47**	43	43
Venezuela affiliate	**29**	31	25

5 Includes branded and unbranded gasoline.

6 Includes sales of affiliates (MBPD): **420** 475 471

7 In 2015, the company sold its interests in affiliates in Australia and New Zealand, which included operable capacities of 55,000 and 12,000 barrels per day, respectively.

Liquidity and Capital Resources

Cash, Cash Equivalents, Time Deposits and Marketable Securities Total balances were $11.3 billion and $13.2 billion at December 31, 2015 and 2014, respectively. Cash provided by operating activities in 2015 was $19.5 billion, compared with $31.5 billion in 2014 and $35.0 billion in 2013. Cash provided by operating activities was net of contributions to employee pension plans of approximately $0.9 billion, $0.4 billion and $1.2 billion in 2015, 2014 and 2013, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of $5.7 billion in 2015, $5.7 billion in 2014, and $1.1 billion in 2013.

Restricted cash of $1.1 billion and $1.5 billion at December 31, 2015 and 2014, respectively, was held in cash and short-term marketable securities and recorded as "Deferred charges and other assets" on the Consolidated Balance Sheet. These amounts are generally associated with upstream abandonment activities, tax payments, and funds held in escrow for tax-deferred exchanges and asset acquisitions and divestitures.

Dividends Dividends paid to common stockholders were $8.0 billion in 2015, $7.9 billion in 2014 and $7.5 billion in 2013.

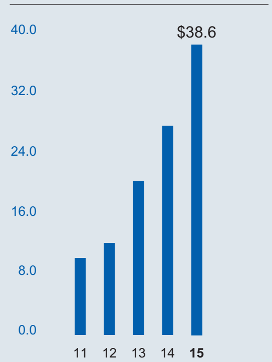
Debt and Capital Lease Obligations Total debt and capital lease obligations were $38.6 billion at December 31, 2015, up from $27.8 billion at year-end 2014.

The $10.8 billion increase in total debt and capital lease obligations during 2015 was primarily due to funding the company's capital investment program, which included several large projects in the construction phase. The company completed bond issuances of $6 billion and $5 billion in March and November 2015, respectively. 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 $12.9 billion at December 31, 2015, compared with $11.8 billion at year-end 2014. Of these amounts, $8.0 billion was reclassified to long-term at the end of both periods. At year-end 2015, settlement of these obligations was not expected to require the use of working capital in 2016, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

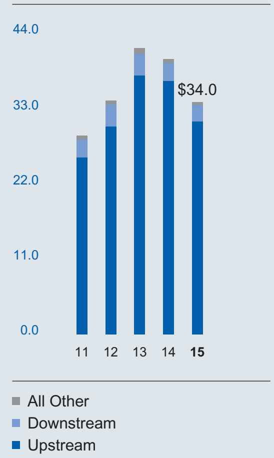
Chevron has an automatic shelf registration statement that expires in August 2018 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

Cash Provided by Operating Activities
Billions of dollars

Total Debt at Year-End
Billions of dollars

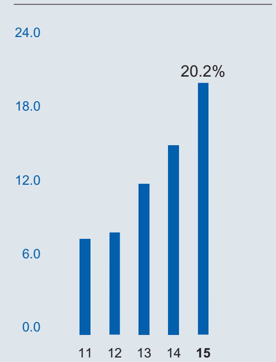


Total Capital & Exploratory Expenditures*
Billions of dollars



*Includes equity in affiliates. Excludes the acquisition of Atlas Energy, Inc. in 2011.

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. In February 2016, Standard & Poor's Corporation changed its rating for these securities from AA to AA-. These securities are rated Aa1 by Moody's Investors

Service. The company's U.S. commercial paper is rated A-1+ by Standard & Poor's and P-l by Moody's. All of these ratings denote high-quality, investment-grade securities.

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

Committed Credit Facilities Information related to committed credit facilities is included in Note 19 to the Consolidated Financial Statements, Short-Term Debt, on page 56.

Common Stock Repurchase Program In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits. The company did not acquire any shares under the program in 2015. From the inception of the program through 2014, the company had purchased 180.9 million shares for $20.0 billion.

Capital and Exploratory Expenditures

Capital and exploratory expenditures by business segment for 2015, 2014 and 2013 are as follows:

			2015			2014			2013
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream	**$ 7,582**	**$ 23,535**	**$31,117**	$ 8,799	$ 28,316	$37,115	$ 8,480	$ 29,378	$37,858
Downstream	**1,923**	**513**	**2,436**	1,649	941	2,590	1,986	1,189	3,175
All Other	**418**	**8**	**426**	584	27	611	821	23	844
Total	**$ 9,923**	**$ 24,056**	**$33,979**	$ 11,032	$ 29,284	$40,316	$ 11,287	$ 30,590	$41,877
Total, Excluding Equity in Affiliates	**$ 8,579**	**$ 22,003**	**$30,582**	$ 10,011	$ 26,838	$36,849	$ 10,562	$ 28,617	$39,179

Total expenditures for 2015 were $34.0 billion, including $3.4 billion for the company's share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2014 and 2013, expenditures were $40.3 billion and $41.9 billion, respectively, including the company's share of affiliates' expenditures of $3.5 billion and $2.7 billion, respectively.

Of the $34.0 billion of expenditures in 2015, 92 percent, or $31.1 billion, was related to upstream activities. Approximately 92 percent and 90 percent was expended for upstream operations in 2014 and 2013, respectively. International upstream accounted for 76 percent of the worldwide upstream investment in 2015, 76 percent in 2014 and 78 percent in 2013.

The company estimates that 2016 capital and exploratory expenditures will be $26.6 billion, including $4.5 billion of spending by affiliates. This planned reduction, compared to 2015 expenditures, is in response to current crude oil market conditions. Approximately 90 percent of the total, or $24.0 billion, is budgeted for exploration and production activities. Approximately $9 billion of planned upstream capital spending is for existing base producing assets, which include shale and tight resource investments. Approximately $11 billion is related to major capital projects currently underway, and approximately $3 billion relates to projects yet to be sanctioned. Global exploration funding accounts for approximately $1 billion. The company will continue to monitor crude oil market conditions, and will further restrict capital outlays should current oil price conditions persist.

Worldwide downstream spending in 2016 is estimated at $2.2 billion, with $1.6 billion for projects in the United States.

Investments in technology companies and other corporate businesses in 2016 are budgeted at $0.4 billion.

Noncontrolling Interests The company had noncontrolling interests of $1.2 billion at both December 31, 2015, and December 31, 2014. Distributions to noncontrolling interests totaled $128 million and $47 million in 2015 and 2014, respectively.

Pension Obligations Information related to pension plan contributions is included on page 64 in Note 23 to the Consolidated Financial Statements under the heading "Cash Contributions and Benefit Payments."

Financial Ratios

	At December 31		
	2015	2014	2013
Current Ratio	**1.3**	1.3	1.5
Interest Coverage Ratio	**9.9**	87.2	126.2
Debt Ratio	**20.2 %**	15.2 %	12.1 %

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 2015, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $3.7 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 2015 was lower than 2014 and 2013 due to lower 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 in 2015 was higher than 2014 and 2013 as the company took on more debt to finance its ongoing investment program.

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2016 – $2.1 billion; 2017 – $1.9 billion; 2018 – $1.7 billion; 2019 – $1.5 billion; 2020 – $1.1 billion; 2020 and after – $3.1 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $1.9 billion in 2015, $3.7 billion in 2014 and $3.6 billion in 2013.

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

		Payments Due by Period			
Millions of dollars	Total[1]	2016	2017-2018	2019-2020	After 2020
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 4,928	$ 4,928	$ —	$ —	$ —
Long-Term Debt[3]	33,584	—	20,023	6,704	6,857
Noncancelable Capital Lease Obligations	150	23	40	25	62
Interest	3,052	563	994	615	880
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	3,348	846	1,243	731	528
Throughput and Take-or-Pay Agreements[4]	6,042	634	1,352	1,294	2,762
Other Unconditional Purchase Obligations[4]	5,293	1,480	2,228	1,276	309

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 23 beginning on page 59.

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 $8.0 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2017–2018 period.

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

Direct Guarantees

		Commitment Expiration by Period			
Millions of dollars	Total	2016	2017-2018	2019-2020	After 2020
Guarantee of nonconsolidated affiliate or joint-venture obligations	$447	$38	$76	$76	$257

The company's guarantee of $447 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 12-year remaining term of the 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 its obligation under this guarantee.

Indemnifications Information related to indemnifications is included on page 65 in Note 24 to the Consolidated Financial Statements under the heading "Indemnifications."

Financial and Derivative Instrument Market Risk

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2015 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 2015.

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, which 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 2015 was not material to the company's results of operations.

The company uses the Monte Carlo simulation method with a 95 percent confidence level as its Value-at-Risk (VaR) model to estimate the maximum potential loss in fair value from the effect of adverse changes in market conditions on derivative commodity instruments held or issued. A one-day holding period is used on the assumption that market-risk positions can be liquidated or hedged within one day. Based on these inputs, the VaR for the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2015 and 2014 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, 2015.

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 2015, 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" in Note 15 of the Consolidated Financial Statements, page 49, 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 50 in Note 17 to the Consolidated Financial Statements under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 17 to the Consolidated Financial Statements under the heading "Ecuador," beginning on page 50.

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	**2015**	2014	2013
Balance at January 1	**$ 1,683**	$ 1,456	$ 1,403
Net Additions	**365**	636	488
Expenditures	**(470)**	(409)	(435)
Balance at December 31	**$ 1,578**	$ 1,683	$ 1,456

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 $15.6 billion for asset retirement obligations at year-end 2015 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 2015 environmental expenditures. Refer to Note 24 on page 66 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 25 on page 67 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 21 to the Consolidated Financial Statements, Accounting for Suspended Exploratory Wells, beginning on page 57.

Income Taxes Information related to income tax contingencies is included on pages 53 through 56 in Note 18 and page 65 in Note 24 to the Consolidated Financial Statements under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page 66 in Note 24 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 (e.g., the Paris Accord and the Kyoto Protocol) and national (e.g., carbon tax, cap-and-trade, or efficiency standards), regional, and state legislation (e.g., California's AB32 or other low carbon fuel standards) and regulatory measures (e.g., the U.S. Environmental Protection Agency's methane performance standards) to limit or reduce greenhouse gas (GHG) emissions are currently in various stages of discussion or implementation. Consideration of GHG issues and the responses to those issues through international agreements and national, regional or state legislation or regulation are integrated into the company's strategy, planning and capital investment reviews, 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 international, national and state levels. Refer to "Risk Factors" in Part I, Item 1A, on pages 21 through 23 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 into the environment; remediate and restore areas damaged by prior releases of nitrogen oxide, sulfur oxide, or other 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 2015 at approximately $2.7 billion for its consolidated companies. Included in these expenditures were approximately $0.9 billion of environmental capital expenditures and $1.8 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 2016, total worldwide environmental capital expenditures are estimated at $0.6 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 2015, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for

oil and gas properties was $13.9 billion, and proved developed reserves at the beginning of 2015 were 4.7 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 2015 would have increased by approximately $730 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 74, for the changes in proved reserve estimates for the three years ending December 31, 2015, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 80 for estimates of proved reserve values for each of the three years ended December 31, 2015.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1 to the Consolidated Financial Statements, beginning on page 36, 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 16 beginning on page 49 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page 36.

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. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed of. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets' associated carrying values.

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

The company reported impairments for certain oil and gas properties during 2015 primarily as a result of downward revisions in the company's longer-term crude oil price outlook. The impairments were primarily in Brazil and the United States. No material individual impairments of PP&E or Investments were recorded for the years 2014 and 2013. 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 2015 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 25 on page 67 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 23, beginning on page 59, 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 62 in Note 23 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

For 2015, the company used an expected long-term rate of return of 7.5 percent and a discount rate of 3.7 percent for U.S. pension plans. The actual return for 2015 was slightly negative due to a broad decline in financial markets in the second half of the year. For the 10 years ending December 31, 2015, actual asset returns averaged 5.0 percent for the plan. Additionally, with the exception of three years within this 10-year period, actual asset returns for this plan equaled or exceeded 7.5 percent during each year.

Total pension expense for 2015 was \$1.2 billion. An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in this assumption for the company's primary U.S. pension plan, which accounted for about 61 percent of companywide pension expense, would have reduced total pension plan expense for 2015 by approximately \$95 million. A 1 percent increase in the discount rate for this same plan would have reduced pension expense for 2015 by approximately \$221 million.

The aggregate funded status recognized at December 31, 2015, was a net liability of approximately \$4.5 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At December 31, 2015, the company used a discount rate of 4.0 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 63 percent of the companywide pension obligation, would have reduced the plan obligation by approximately \$384 million, which would have decreased the plan's underfunded status from approximately \$1.7 billion to \$1.3 billion.

For the company's OPEB plans, expense for 2015 was \$271 million, and the total liability, which reflected the unfunded status of the plans at the end of 2015, was \$3.3 billion. For the main U.S. OPEB plan, the company used a 4.1 percent discount rate to measure expense in 2015, and a 4.5 percent discount rate to measure the benefit obligations at December 31, 2015. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2015 OPEB expense and OPEB liabilities at the end of 2015. For information on the sensitivity of the health care cost-trend rate, refer to page 62 in Note 23 under the heading "Other Benefit Assumptions."

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are included in actuarial gain/loss. Refer to page 61 in Note 23 for a description of the method used to amortize the \$6.3 billion of before-tax actuarial losses recorded by the company as of December 31, 2015, and an estimate of the costs to be recognized in expense during 2016. In addition, information related to company contributions is included on page 64 in Note 23 under the heading "Cash Contributions and Benefit Payments."

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

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is "more likely than not" (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 24 beginning on page 65. 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, 2015.

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

New Accounting Standards

Refer to Note 5 on page 40 for information regarding new accounting standards.

Quarterly Results and Stock Market Data

Unaudited

				2015				2014
Millions of dollars, except per-share amounts	**4th Q**	**3rd Q**	**2nd Q**	**1st Q**	4th Q	3rd Q	2nd Q	1st Q
Revenues and Other Income								
Sales and other operating revenues[1]	**$28,014**	**$32,767**	**$36,829**	**$32,315**	$42,111	$51,822	$55,583	$50,978
Income from equity affiliates	**919**	**1,195**	**1,169**	**1,401**	1,555	1,912	1,709	1,922
Other income	**314**	**353**	**2,359**	**842**	2,422	945	646	365
Total Revenues and Other Income	**29,247**	**34,315**	**40,357**	**34,558**	46,088	54,679	57,938	53,265
Costs and Other Deductions								
Purchased crude oil and products	**14,570**	**17,447**	**20,541**	**17,193**	24,263	30,741	33,844	30,823
Operating expenses	**5,970**	**5,592**	**6,077**	**5,395**	6,572	6,403	6,287	6,023
Selling, general and administrative expenses	**1,303**	**1,026**	**1,170**	**944**	1,368	1,122	1,077	927
Exploration expenses	**1,358**	**315**	**1,075**	**592**	510	366	694	415
Depreciation, depletion and amortization	**5,400**	**4,268**	**6,958**	**4,411**	4,873	3,948	3,842	4,130
Taxes other than on income[1]	**2,856**	**2,883**	**3,173**	**3,118**	3,118	3,236	3,167	3,019
Total Costs and Other Deductions	**31,457**	**31,531**	**38,994**	**31,653**	40,704	45,816	48,911	45,337
Income (Loss) Before Income Tax Expense	**(2,210)**	**2,784**	**1,363**	**2,905**	5,384	8,863	9,027	7,928
Income Tax Expense (Benefit)	**(1,655)**	**727**	**755**	**305**	1,912	3,236	3,337	3,407
Net Income (Loss)	**$ (555)**	**$ 2,057**	**$ 608**	**$ 2,600**	$ 3,472	$ 5,627	$ 5,690	$ 4,521
Less: Net income attributable to noncontrolling interests	**33**	**20**	**37**	**33**	1	34	25	9
Net Income (Loss) Attributable to Chevron Corporation	**$ (588)**	**$ 2,037**	**$ 571**	**$ 2,567**	$ 3,471	$ 5,593	$ 5,665	$ 4,512
Per Share of Common Stock								
Net Income (Loss) Attributable to Chevron Corporation								
– Basic	**$ (0.31)**	**$ 1.09**	**$ 0.30**	**$ 1.38**	$ 1.86	$ 2.97	$ 3.00	$ 2.38
– Diluted	**$ (0.31)**	**$ 1.09**	**$ 0.30**	**$ 1.37**	$ 1.85	$ 2.95	$ 2.98	$ 2.36
Dividends	**$ 1.07**	**$ 1.07**	**$ 1.07**	**$ 1.07**	$ 1.07	$ 1.07	$ 1.07	$ 1.00
Common Stock Price Range – High[2]	**$ 98.64**	**$ 96.67**	**$112.20**	**$113.00**	$120.17	$135.10	$133.57	$125.32
– Low[2]	**$ 77.31**	**$ 69.58**	**$ 96.22**	**$ 98.88**	$100.15	$118.66	$116.50	$109.27
[1] Includes excise, value-added and similar taxes:	**$ 1,717**	**$ 1,800**	**$ 1,965**	**$ 1,877**	$ 2,004	$ 2,116	$ 2,120	$ 1,946

[2] Intraday price.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 15, 2016, stockholders of record numbered approximately 145,000. There are no restrictions on the company's ability to pay dividends.

Management's Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

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

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

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

The company's management has evaluated, with the participation of the Chief Executive Officer and Chief Financial Officer, the effectiveness of the company's disclosure controls and procedures (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2015. 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, 2015.

The effectiveness of the company's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

John S. Watson 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 25, 2016

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Chevron Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, equity and of cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2015, and December 31, 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these 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 the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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 25, 2016

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

	Year ended December 31		
	2015	2014	2013
Revenues and Other Income			
Sales and other operating revenues*	**$ 129,925**	$ 200,494	$ 220,156
Income from equity affiliates	**4,684**	7,098	7,527
Other income	**3,868**	4,378	1,165
Total Revenues and Other Income	**138,477**	211,970	228,848
Costs and Other Deductions			
Purchased crude oil and products	**69,751**	119,671	134,696
Operating expenses	**23,034**	25,285	24,627
Selling, general and administrative expenses	**4,443**	4,494	4,510
Exploration expenses	**3,340**	1,985	1,861
Depreciation, depletion and amortization	**21,037**	16,793	14,186
Taxes other than on income*	**12,030**	12,540	13,063
Total Costs and Other Deductions	**133,635**	180,768	192,943
Income Before Income Tax Expense	**4,842**	31,202	35,905
Income Tax Expense	**132**	11,892	14,308
Net Income	**4,710**	19,310	21,597
Less: Net income attributable to noncontrolling interests	**123**	69	174
Net Income Attributable to Chevron Corporation	**$ 4,587**	$ 19,241	$ 21,423
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
– Basic	**$ 2.46**	$ 10.21	$ 11.18
– Diluted	**$ 2.45**	$ 10.14	$ 11.09
* Includes excise, value-added and similar taxes.	**$ 7,359**	$ 8,186	$ 8,492

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2015	2014	2013
Net Income	**$ 4,710**	$ 19,310	$ 21,597
Currency translation adjustment			
Unrealized net change arising during period	**(44)**	(73)	42
Unrealized holding loss on securities			
Net loss arising during period	**(21)**	(2)	(7)
Derivatives			
Net derivatives loss on hedge transactions	**—**	(66)	(111)
Reclassification to net income of net realized gain	**—**	(17)	(1)
Income taxes on derivatives transactions	**—**	29	39
Total	**—**	(54)	(73)
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	**794**	757	866
Actuarial gain (loss) arising during period	**109**	(2,730)	3,379
Prior service credits (cost)			
Amortization to net income of net prior service costs (credits) and curtailments	**30**	26	(27)
Prior service credits (costs) arising during period	**6**	(6)	60
Defined benefit plans sponsored by equity affiliates	**30**	(99)	164
Income taxes on defined benefit plans	**(336)**	901	(1,614)
Total	**633**	(1,151)	2,828
Other Comprehensive Gain (Loss), Net of Tax	**568**	(1,280)	2,790
Comprehensive Income	**5,278**	18,030	24,387
Comprehensive income attributable to noncontrolling interests	**(123)**	(69)	(174)
Comprehensive Income Attributable to Chevron Corporation	**$ 5,155**	$ 17,961	$ 24,213

See accompanying Notes to the Consolidated Financial Statements.

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

	At December 31	
	2015	2014
Assets		
Cash and cash equivalents	**$ 11,022**	$ 12,785
Time deposits	**—**	8
Marketable securities	**310**	422
Accounts and notes receivable (less allowance: 2015 - $313; 2014 - $59)	**12,860**	16,736
Inventories:		
Crude oil and petroleum products	**3,535**	3,854
Chemicals	**490**	467
Materials, supplies and other	**2,309**	2,184
Total inventories	**6,334**	6,505
Prepaid expenses and other current assets	**4,821**	5,776
Total Current Assets	**35,347**	42,232
Long-term receivables, net	**2,412**	2,817
Investments and advances	**27,110**	26,912
Properties, plant and equipment, at cost	**340,277**	327,289
Less: Accumulated depreciation, depletion and amortization	**151,881**	144,116
Properties, plant and equipment, net	**188,396**	183,173
Deferred charges and other assets	**6,801**	6,299
Goodwill	**4,588**	4,593
Assets held for sale	**1,449**	—
Total Assets	**$ 266,103**	$ 266,026
Liabilities and Equity		
Short-term debt	**$ 4,928**	$ 3,790
Accounts payable	**13,516**	19,000
Accrued liabilities	**4,833**	5,328
Federal and other taxes on income	**2,069**	2,575
Other taxes payable	**1,118**	1,233
Total Current Liabilities	**26,464**	31,926
Long-term debt	**33,584**	23,960
Capital lease obligations	**80**	68
Deferred credits and other noncurrent obligations	**23,465**	23,549
Noncurrent deferred income taxes	**20,689**	21,920
Noncurrent employee benefit plans	**7,935**	8,412
Total Liabilities	**112,217**	109,835
Preferred stock (authorized 100,000,000 shares; $1.00 par value; none issued)	**—**	—
Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2015 and 2014)	**1,832**	1,832
Capital in excess of par value	**16,330**	16,041
Retained earnings	**181,578**	184,987
Accumulated other comprehensive loss	**(4,291)**	(4,859)
Deferred compensation and benefit plan trust	**(240)**	(240)
Treasury stock, at cost (2015 - 559,862,580 shares; 2014 - 563,027,772 shares)	**(42,493)**	(42,733)
Total Chevron Corporation Stockholders' Equity	**152,716**	155,028
Noncontrolling interests	**1,170**	1,163
Total Equity	**153,886**	156,191
Total Liabilities and Equity	**$ 266,103**	$ 266,026

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2015	2014	2013
Operating Activities			
Net Income	**$ 4,710**	$ 19,310	$ 21,597
Adjustments			
Depreciation, depletion and amortization	**21,037**	16,793	14,186
Dry hole expense	**2,309**	875	683
Distributions less than income from equity affiliates	**(760)**	(2,202)	(1,178)
Net before-tax gains on asset retirements and sales	**(3,215)**	(3,540)	(639)
Net foreign currency effects	**(82)**	(277)	(103)
Deferred income tax provision	**(1,861)**	1,572	1,876
Net increase in operating working capital	**(1,979)**	(540)	(1,331)
(Increase) decrease in long-term receivables	**(59)**	(9)	183
Decrease (increase) in other deferred charges	**25**	263	(321)
Cash contributions to employee pension plans	**(868)**	(392)	(1,194)
Other	**199**	(378)	1,243
Net Cash Provided by Operating Activities	**19,456**	31,475	35,002
Investing Activities			
Capital expenditures	**(29,504)**	(35,407)	(37,985)
Proceeds and deposits related to asset sales	**5,739**	5,729	1,143
Net maturities of time deposits	**8**	—	700
Net sales (purchases) of marketable securities	**122**	(148)	3
Net (borrowing) repayment of loans by equity affiliates	**(217)**	140	314
Net sales (purchases) of other short-term investments	**44**	(207)	216
Net Cash Used for Investing Activities	**(23,808)**	(29,893)	(35,609)
Financing Activities			
Net (repayments) borrowings of short-term obligations	**(335)**	3,431	2,378
Proceeds from issuances of long-term debt	**11,091**	4,000	6,000
Repayments of long-term debt and other financing obligations	**(32)**	(43)	(132)
Cash dividends - common stock	**(7,992)**	(7,928)	(7,474)
Distributions to noncontrolling interests	**(128)**	(47)	(99)
Net sales (purchases) of treasury shares	**211**	(4,412)	(4,494)
Net Cash Provided by (Used for) Financing Activities	**2,815**	(4,999)	(3,821)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(226)**	(43)	(266)
Net Change in Cash and Cash Equivalents	**(1,763)**	(3,460)	(4,694)
Cash and Cash Equivalents at January 1	**12,785**	16,245	20,939
Cash and Cash Equivalents at December 31	**$ 11,022**	$ 12,785	$ 16,245

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2015		2014		2013	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Preferred Stock	**—**	**$ —**	—	$ —	—	$ —
Common Stock	**2,442,677**	**$ 1,832**	2,442,677	$ 1,832	2,442,677	$ 1,832
Capital in Excess of Par						
Balance at January 1		**$ 16,041**		$ 15,713		$ 15,497
Treasury stock transactions		**289**		328		216
Balance at December 31		**$ 16,330**		$ 16,041		$ 15,713
Retained Earnings						
Balance at January 1		**$ 184,987**		$ 173,677		$ 159,730
Net income attributable to Chevron Corporation		**4,587**		19,241		21,423
Cash dividends on common stock		**(7,992)**		(7,928)		(7,474)
Stock dividends		**(3)**		(3)		(3)
Tax (charge) benefit from dividends paid on unallocated ESOP shares and other		**(1)**		—		1
Balance at December 31		**$ 181,578**		$ 184,987		$ 173,677
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (96)**		$ (23)		$ (65)
Change during year		**(44)**		(73)		42
Balance at December 31		**$ (140)**		$ (96)		$ (23)
Unrealized net holding (loss) gain on securities						
Balance at January 1		**$ (8)**		$ (6)		$ 1
Change during year		**(21)**		(2)		(7)
Balance at December 31		**$ (29)**		$ (8)		$ (6)
Net derivatives (loss) gain on hedge transactions						
Balance at January 1		**$ (2)**		$ 52		$ 125
Change during year		**—**		(54)		(73)
Balance at December 31		**$ (2)**		$ (2)		$ 52
Pension and other postretirement benefit plans						
Balance at January 1		**$ (4,753)**		$ (3,602)		$ (6,430)
Change during year		**633**		(1,151)		2,828
Balance at December 31		**$ (4,120)**		$ (4,753)		$ (3,602)
Balance at December 31		**$ (4,291)**		$ (4,859)		$ (3,579)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ —**		$ —		$ (42)
Net reduction of ESOP debt and other		**—**		—		42
Balance at December 31		**$ —**		$ —		$ —
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240)
Balance at December 31	**14,168**	**$ (240)**	14,168	$ (240)	14,168	$ (240)
Treasury Stock at Cost						
Balance at January 1	**563,028**	**$ (42,733)**	529,074	$ (38,290)	495,979	$ (33,884)
Purchases	**15**	**(2)**	41,592	(5,006)	41,676	(5,004)
Issuances - mainly employee benefit plans	**(3,180)**	**242**	(7,638)	563	(8,581)	598
Balance at December 31	**559,863**	**$ (42,493)**	563,028	$ (42,733)	529,074	$ (38,290)
Total Chevron Corporation Stockholders' Equity at December 31		**$ 152,716**		$ 155,028		$ 149,113
Noncontrolling Interests		**$ 1,170**		$ 1,163		$ 1,314
Total Equity		**$ 153,886**		$ 156,191		$ 150,427

See accompanying Notes to the Consolidated Financial Statements.

Note 1
Summary of Significant Accounting Policies

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

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

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

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

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

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

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

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

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 21, beginning on page 57, 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 before-tax 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 before-tax 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 9, beginning on page 42, 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 25, on page 67, 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. Periodic valuation provisions for impairment 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 on an annual basis and between annual tests 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 25, on page 67, for a discussion of the company's AROs.

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

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

Revenue Recognition Revenues associated with sales of crude oil, natural gas, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized using the entitlement method. Excise, value-added and similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income, on page 31. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in "Purchased crude oil and products" on the Consolidated Statement of Income.

Stock Options and Other Share-Based Compensation The company issues stock options and other share-based compensation to certain employees. For equity awards, such as stock options, total compensation cost is based on the grant date fair value, and for liability awards, such as stock appreciation rights, total compensation cost is based on the settlement value. The company recognizes stock-based compensation expense for all awards over the service period required to earn the award, which is the shorter of the vesting period or the time period an employee becomes eligible to retain the award at retirement. Stock options and stock appreciation rights granted under the company's Long-Term Incentive Plan have graded vesting provisions by which one-third of each award vests on the first, second and third anniversaries of the date of grant. The company amortizes these graded awards on a straight-line basis.

Note 2

Changes in Accumulated Other Comprehensive Losses

The change in Accumulated Other Comprehensive Losses (AOCL) presented on the Consolidated Balance Sheet and the impact of significant amounts reclassified from AOCL on information presented in the Consolidated Statement of Income for the year ending December 31, 2015, are reflected in the table below.

	Year Ended December 31, 2015[1]				
	Currency Translation Adjustment	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total
Balance at January 1	$ (96)	$ (8)	$ (2)	$ (4,753)	$ (4,859)
Components of Other Comprehensive Income (Loss):					
Before Reclassifications	(44)	(21)	—	126	61
Reclassifications[2]	—	—	—	507	507
Net Other Comprehensive Income (Loss)	(44)	(21)	—	633	568
Balance at December 31	$ (140)	$ (29)	$ (2)	$ (4,120)	$ (4,291)

1 All amounts are net of tax.
2 Refer to Note 23 beginning on page 59, for reclassified components totaling $824 that are included in employee benefit costs for the year ending December 31, 2015. Related income taxes for the same period, totaling $317, are reflected in Income Tax Expense on the Consolidated Statement of Income. All other reclassified amounts were insignificant.

Note 3

Noncontrolling Interests

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

Activity for the equity attributable to noncontrolling interests for 2015, 2014 and 2013 is as follows:

	2015	2014	2013
Balance at January 1	**$ 1,163**	$ 1,314	$ 1,308
Net income	**123**	69	174
Distributions to noncontrolling interests	**(128)**	(47)	(99)
Other changes, net	**12**	(173)	(69)
Balance at December 31	**$ 1,170**	$ 1,163	$ 1,314

Note 4
Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2015	2014	2013
Net increase in operating working capital was composed of the following:			
Decrease (increase) in accounts and notes receivable	**$ 3,631**	$ 4,491	$ (1,101)
Decrease (increase) in inventories	**85**	(146)	(237)
Decrease (increase) in prepaid expenses and other current assets	**713**	(407)	834
(Decrease) increase in accounts payable and accrued liabilities	**(5,769)**	(3,737)	160
Decrease in income and other taxes payable	**(639)**	(741)	(987)
Net increase in operating working capital	**$ (1,979)**	$ (540)	$ (1,331)
Net cash provided by operating activities includes the following cash payments for income taxes:			
Income taxes	**$ 4,645**	$ 10,562	$ 12,898
Net sales (purchases) of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (6)**	$ (162)	$ (7)
Marketable securities sold	**128**	14	10
Net sales (purchases) of marketable securities	**$ 122**	$ (148)	$ 3
Net maturities of time deposits consisted of the following gross amounts:			
Investments in time deposits	**$ —**	$ (317)	$ (2,317)
Maturities of time deposits	**8**	317	3,017
Net maturities of time deposits	**$ 8**	$ —	$ 700
Net (repayments) borrowings of short-term obligations consisted of the following gross and net amounts:			
Proceeds from issuances of short-term obligations	**$ 13,805**	$ 9,070	$ 1,551
Repayments of short-term obligations	**(16,379)**	(4,612)	(375)
Net borrowings (repayments) of short-term obligations with three months or less maturity	**2,239**	(1,027)	1,202
Net (repayments) borrowings of short-term obligations	**$ (335)**	$ 3,431	$ 2,378

The "Net increase in operating working capital" includes reductions of $17, $58 and $79 for excess income tax benefits associated with stock options exercised during 2015, 2014 and 2013, respectively. These amounts are offset by an equal amount in "Net sales (purchases) of treasury shares." "Other" includes changes in postretirement benefits obligations and other long-term liabilities.

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 $2, $5,006 and $5,004 in 2015, 2014 and 2013, respectively. No purchases were made under the company's share repurchase program in 2015. In 2014 and 2013, the company purchased 41.5 million and 41.6 million common shares for $5,000 and $5,000 under its share repurchase program, respectively.

In 2015, 2014 and 2013, "Net sales (purchases) of other short-term investments" generally consisted of restricted cash associated with upstream abandonment activities, tax payments, and funds held in escrow for tax-deferred exchanges and asset acquisitions and divestitures that was invested in cash and short-term securities and reclassified from "Cash and cash equivalents" to "Deferred charges and other assets" on the Consolidated Balance Sheet.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. "Depreciation, depletion and amortization," "Dry hole expense" and "Deferred income tax provision" collectively include approximately $3,700 in non-cash reductions to properties, plant and equipment recorded in 2015 relating to impairments and project suspensions and associated adverse tax effects, primarily as a result of downward revisions in the company's longer-term crude oil price outlook.

Refer also to Note 25, on page 67, 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, 2015.

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	
	2015	2014	2013
Additions to properties, plant and equipment *	**$ 28,213**	$ 34,393	$ 36,550
Additions to investments	**555**	526	934
Current-year dry hole expenditures	**736**	504	594
Payments for other liabilities and assets, net	**—**	(16)	(93)
Capital expenditures	**29,504**	35,407	37,985
Expensed exploration expenditures	**1,031**	1,110	1,178
Assets acquired through capital lease obligations and other financing obligations	**47**	332	16
Capital and exploratory expenditures, excluding equity affiliates	**30,582**	36,849	39,179
Company's share of expenditures by equity affiliates	**3,397**	3,467	2,698
Capital and exploratory expenditures, including equity affiliates	**$ 33,979**	$ 40,316	$ 41,877

* Excludes noncash additions of $1,362 in 2015, $2,310 in 2014 and $1,661 in 2013.

Note 5
New Accounting Standards

Revenue Recognition (Topic 606), Revenue from Contracts with Customers (ASU 2014-09) In July 2015, the FASB approved a one-year deferral of the effective date of ASU 2014-09, which becomes effective for the company January 1, 2018. Early adoption is permitted at the original effective date of January 1, 2017. The standard provides a single comprehensive revenue recognition model for contracts with customers, eliminates most industry-specific revenue recognition guidance, and expands disclosure requirements. The company is evaluating the effect of the standard on its consolidated financial statements. The company does not intend to proceed with early adoption.

Income Taxes (Topic 740), Balance Sheet Classification of Deferred Taxes (ASU 2015-17) In November 2015, FASB issued ASU 2015-17, which becomes effective for the company January 1, 2017. Early adoption is permitted. The standard provides that all deferred income taxes be classified as noncurrent on the balance sheet. The current requirement is to classify most deferred tax assets and liabilities based on the classification of the underlying asset or liability. Adoption of the standard will not have an impact on the company's results of operations or liquidity.

Note 6
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, service stations, bareboat charters, office buildings, and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on operating leases are recorded as expense. Details of the capitalized leased assets are as follows:

	At December 31	
	2015	2014
Upstream	**$ 800**	$ 765
Downstream	**98**	97
All Other	**—**	—
Total	**898**	862
Less: Accumulated amortization	**448**	381
Net capitalized leased assets	**$ 450**	$ 481

Rental expenses incurred for operating leases during 2015, 2014 and 2013 were as follows:

	Year ended December 31		
	2015	2014	2013
Minimum rentals	**$ 1,041**	$ 1,080	$ 1,049
Contingent rentals	**2**	1	1
Total	**1,043**	1,081	1,050
Less: Sublease rental income	**9**	14	25
Net rental expense	**$ 1,034**	$ 1,067	$ 1,025

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

At December 31, 2015, 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 2016	$ 846	$ 23
2017	689	21
2018	554	19
2019	420	19
2020	311	6
Thereafter	528	62
Total	$ 3,348	$ 150
Less: Amounts representing interest and executory costs		$ (53)
Net present values		97
Less: Capital lease obligations included in short-term debt		(17)
Long-term capital lease obligations		$ 80

Note 7

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		
	2015	2014	2013
Sales and other operating revenues	**$ 97,766**	$ 157,198	$ 174,318
Total costs and other deductions	**101,565**	153,139	169,984
Net income (loss) attributable to CUSA	**(1,054)**	3,849	3,714

	2015	2014
Current assets	**$ 9,732**	$ 13,724
Other assets	**59,170**	62,195
Current liabilities	**13,664**	16,191
Other liabilities	**29,100**	30,175
Total CUSA net equity	**$ 26,138**	$ 29,553
Memo: Total debt	**$ 14,462**	$ 14,473

Note 8

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 15, beginning on page 48, for a discussion of TCO operations. Summarized financial information for 100 percent of TCO is presented in the table below:

	Year ended December 31		
	2015	2014	2013
Sales and other operating revenues	**$ 12,811**	$ 22,813	$ 25,239
Costs and other deductions	**7,257**	10,275	11,173
Net income attributable to TCO	**3,897**	8,772	9,855

	At December 31	
	2015	2014
Current assets	**$ 2,098**	$ 3,425
Other assets	**17,094**	14,810
Current liabilities	**1,063**	1,531
Other liabilities	**2,266**	2,375
Total TCO net equity	**$ 15,863**	$ 14,329

Note 9

Fair Value Measurements

The tables below and on the next page show the fair value hierarchy for assets and liabilities measured at fair value on a recurring and nonrecurring basis at December 31, 2015, and December 31, 2014.

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, 2015.

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 reported impairments for certain oil and gas properties during 2015 primarily as a result of downward revisions in the company's longer-term crude oil price outlook. The impairments were primarily in Brazil and the United States. The company reported impairments for certain oil and gas properties and a mining asset in 2014.

Investments and Advances The company did not have any material investments and advances measured at fair value on a nonrecurring basis to report in 2015 or 2014.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2015				At December 31, 2014			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	**$ 310**	**$ 310**	**$ —**	**$ —**	$ 422	$ 422	$ —	$ —
Derivatives	**205**	**189**	**16**	**—**	413	394	19	—
Total Assets at Fair Value	**$ 515**	**$ 499**	**$ 16**	**$ —**	$ 835	$ 816	$ 19	$ —
Derivatives	**53**	**47**	**6**	**—**	84	83	1	—
Total Liabilities at Fair Value	**$ 53**	**$ 47**	**$ 6**	**$ —**	$ 84	$ 83	$ 1	$ —

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 2015	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2014
Properties, plant and equipment, net (held and used)	**$ 3,051**	**$ —**	**$ 239**	**$ 2,812**	**$ 3,222**	$ 947	$ —	$ 213	$ 734	$ 1,249
Properties, plant and equipment, net (held for sale)	**937**	**—**	**937**	**—**	**844**	—	—	—	—	25
Investments and advances	**75**	**—**	**75**	**—**	**28**	11	—	—	11	41
Total Nonrecurring Assets at Fair Value	**$ 4,063**	**$ —**	**$ 1,251**	**$ 2,812**	**$ 4,094**	$ 958	$ —	$ 213	$ 745	$ 1,315

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 $11,022 and $12,785 at December 31, 2015, and December 31, 2014, respectively. The instruments held in "Time deposits" are bank time deposits with maturities greater than 90 days, and had carrying/fair values of zero and $8 at December 31, 2015, and December 31, 2014, 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, 2015.

"Cash and cash equivalents" do not include investments with a carrying/fair value of $1,100 and $1,474 at December 31, 2015, and December 31, 2014, respectively. At December 31, 2015, these investments are classified as Level 1 and include restricted funds related to upstream abandonment activities, tax payments, and funds held in escrow for tax-deferred exchanges and asset acquisitions and divestitures, which are reported in "Deferred charges and other assets" on the Consolidated Balance Sheet. Long-term debt of $25,584 and $15,960 at December 31, 2015, and December 31, 2014, had estimated fair values of $25,884 and $16,450, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is $25,117 and classified as Level 1. The fair value of the other bonds is $767 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, 2015 and 2014, were not material.

Note 10

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, 2015, December 31, 2014, and December 31, 2013, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are on the next page:

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

		At December 31	
Type of Contract	Balance Sheet Classification	**2015**	2014
Commodity	Accounts and notes receivable, net	**$ 200**	$ 401
Commodity	Long-term receivables, net	**5**	12
Total Assets at Fair Value		**$ 205**	$ 413
Commodity	Accounts payable	**$ 51**	$ 57
Commodity	Deferred credits and other noncurrent obligations	**2**	27
Total Liabilities at Fair Value		**$ 53**	$ 84

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

Type of Derivative	Statement of	Gain/(Loss) Year ended December 31		
Contract	Income Classification	**2015**	2014	2013
Commodity	Sales and other operating revenues	**$ 277**	$ 553	$ (108)
Commodity	Purchased crude oil and products	**30**	(17)	(77)
Commodity	Other income	**(3)**	(32)	(9)
		$ 304	$ 504	$ (194)

The table below represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2015 and December 31, 2014.

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

At December 31, 2015	Gross Amount Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset	Net Amount
Derivative Assets	$ 2,459	$ 2,254	$ 205	$ —	$ 205
Derivative Liabilities	$ 2,307	$ 2,254	$ 53	$ —	$ 53
At December 31, 2014					
Derivative Assets	$ 4,004	$ 3,591	$ 413	$ 7	$ 406
Derivative Liabilities	$ 3,675	$ 3,591	$ 84	$ —	$ 84

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 11
Assets Held for Sale

At December 31, 2015, the company classified $1,449 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. These assets are associated with upstream and downstream operations that are anticipated to be sold in the next 12 months. The revenues and earnings contributions of these assets in 2015 were not material.

Note 12
Equity

Retained earnings at December 31, 2015 and 2014, included approximately $15,010 and $14,512, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2015, about 114 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, approximately 120,753 shares remain available for issuance from the 800,000 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 13
Earnings Per Share

Basic earnings per share (EPS) is based upon "Net Income Attributable to Chevron Corporation" ("earnings") and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (refer to Note 22, "Stock Options and Other Share-Based Compensation," beginning on page 58). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2015	2014	2013
Basic EPS Calculation			
Earnings available to common stockholders - Basic*	**$ 4,587**	$ 19,241	$ 21,423
Weighted-average number of common shares outstanding	**1,867**	1,883	1,916
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,868**	1,884	1,917
Earnings per share of common stock - Basic	**$ 2.46**	$ 10.21	$ 11.18
Diluted EPS Calculation			
Earnings available to common stockholders - Diluted*	**$ 4,587**	$ 19,241	$ 21,423
Weighted-average number of common shares outstanding	**1,867**	1,883	1,916
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**7**	14	15
Total weighted-average number of common shares outstanding	**1,875**	1,898	1,932
Earnings per share of common stock - Diluted	**$ 2.45**	$ 10.14	$ 11.09

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

Note 14
Operating Segments and Geographic Data

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

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

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

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

	Year ended December 31		
	2015	2014	2013
Upstream			
United States	$ **(4,055)**	$ 3,327	$ 4,044
International	**2,094**	13,566	16,765
Total Upstream	**(1,961)**	16,893	20,809
Downstream			
United States	**3,182**	2,637	787
International	**4,419**	1,699	1,450
Total Downstream	**7,601**	4,336	2,237
Total Segment Earnings	**5,640**	21,229	23,046
All Other			
Interest income	**65**	77	80
Other	**(1,118)**	(2,065)	(1,703)
Net Income Attributable to Chevron Corporation	$ **4,587**	$ 19,241	$ 21,423

Segment Assets Segment assets do not include intercompany investments or receivables. Assets at year-end 2015 and 2014 are as follows:

	At December 31	
	2015	2014[1]
Upstream		
United States	$ **46,407**	$ 49,343
International	**163,217**	152,736
Goodwill	**4,588**	4,593
Total Upstream	**214,212**	206,672
Downstream		
United States	**21,408**	23,068
International	**14,982**	17,723
Total Downstream	**36,390**	40,791
Total Segment Assets	**250,602**	247,463
All Other		
United States	**5,076**	6,603
International	**10,425**	11,960
Total All Other	**15,501**	18,563
Total Assets – United States	**72,891**	79,014
Total Assets – International	**188,624**	182,419
Goodwill	**4,588**	4,593
Total Assets	$ **266,103**	$ 266,026

[1] 2014 conformed to 2015 presentation.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2015, 2014 and 2013, 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		
	2015	2014	2013
Upstream			
United States	**$ 4,117**	$ 7,455	$ 8,052
Intersegment	**8,631**	15,455	16,865
Total United States	**12,748**	22,910	24,917
International	**15,587**	23,808	17,607
Intersegment	**11,492**	23,107	33,034
Total International	**27,079**	46,915	50,641
Total Upstream*	**39,827**	69,825	75,558
Downstream			
United States	**48,420**	73,942	80,272
Excise and similar taxes	**4,426**	4,633	4,792
Intersegment	**26**	31	39
Total United States	**52,872**	78,606	85,103
International	**54,296**	86,848	105,373
Excise and similar taxes	**2,933**	3,553	3,699
Intersegment	**1,528**	8,839	859
Total International	**58,757**	99,240	109,931
Total Downstream*	**111,629**	177,846	195,034
All Other			
United States	**141**	252	358
Intersegment	**1,372**	1,475	1,524
Total United States	**1,513**	1,727	1,882
International	**5**	3	3
Intersegment	**37**	28	31
Total International	**42**	31	34
Total All Other	**1,555**	1,758	1,916
Segment Sales and Other Operating Revenues			
United States	**67,133**	103,243	111,902
International	**85,878**	146,186	160,606
Total Segment Sales and Other Operating Revenues	**153,011**	249,429	272,508
Elimination of intersegment sales	**(23,086)**	(48,935)	(52,352)
Total Sales and Other Operating Revenues	**$ 129,925**	$ 200,494	$ 220,156

* Effective January 1, 2014, International Upstream prospectively includes selected amounts previously recognized in International Downstream, which are not material to the segments.

Segment Income Taxes Segment income tax expense for the years 2015, 2014 and 2013 is as follows:

	Year ended December 31		
	2015	2014	2013
Upstream			
United States	**$ (2,041)**	$ 2,043	$ 2,333
International	**1,214**	9,217	12,470
Total Upstream	**(827)**	11,260	14,803
Downstream			
United States	**1,320**	1,302	364
International	**1,313**	467	389
Total Downstream	**2,633**	1,769	753
All Other	**(1,674)**	(1,137)	(1,248)
Total Income Tax Expense	**$ 132**	$ 11,892	$ 14,308

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 15, on page 48. Information related to properties, plant and equipment by segment is contained in Note 16, on page 49.

Note 15
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		
	2015	2014	**2015**	2014	2013
Upstream					
Tengizchevroil	**$ 8,077**	$ 7,319	**$ 1,939**	$ 4,392	$ 4,957
Petropiar	**679**	794	**180**	26	339
Caspian Pipeline Consortium	**1,342**	1,487	**162**	191	113
Petroboscan	**1,163**	917	**219**	186	300
Angola LNG Limited	**3,284**	3,277	**(417)**	(311)	(111)
Other	**2,158**	2,316	**135**	229	214
Total Upstream	**16,703**	16,110	**2,218**	4,713	5,812
Downstream					
GS Caltex Corporation	**3,620**	2,867	**824**	420	132
Chevron Phillips Chemical Company LLC	**5,196**	5,116	**1,367**	1,606	1,371
Caltex Australia Ltd.	**—**	1,161	**92**	183	224
Other	**1,077**	1,048	**186**	180	199
Total Downstream	**9,893**	10,192	**2,469**	2,389	1,926
All Other					
Other	**(18)**	33	**(3)**	(4)	(211)
Total equity method	**$ 26,578**	$ 26,335	**$ 4,684**	$ 7,098	$ 7,527
Other at or below cost	**532**	577			
Total investments and advances	**$ 27,110**	$ 26,912			
Total United States	**$ 6,863**	$ 6,787	**$ 1,342**	$ 1,623	$ 1,294
Total International	**$ 20,247**	$ 20,125	**$ 3,342**	$ 5,475	$ 6,233

*2014 conformed to 2015 presentation.

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, 2015, the company's carrying value of its investment in TCO was about $150 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. See Note 8, on page 42, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company which operates the Hamaca heavy-oil production and upgrading project in Venezuela's Orinoco Belt. At December 31, 2015, the company's carrying value of its investment in Petropiar was approximately $160 less than the amount of underlying equity in Petropiar's net assets. The difference represents the excess of Chevron's underlying equity in Petropiar's net assets over the net book value of the assets contributed to the venture.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, a variable interest entity, which provides the critical export route for crude oil from both TCO and Karachaganak. The company has investments and advances totaling $1,342, which includes long-term loans of $1,098 at year-end 2015. The loans were provided to fund 30 percent of the initial pipeline construction. The company is not the primary beneficiary of the consortium because it does not direct activities of the consortium and only receives its proportionate share of the financial returns.

Petroboscan Chevron has a 39.2 percent interest in Petroboscan, a joint stock company which operates the Boscan Field in Venezuela. At December 31, 2015, the company's carrying value of its investment in Petroboscan was approximately $140 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.

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

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

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

Caltex Australia Ltd. Chevron sold its 50 percent equity ownership interest in Caltex Australia Ltd. (CAL) in second quarter 2015.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $4,850, $10,404 and $14,635 with affiliated companies for 2015, 2014 and 2013, respectively. "Purchased crude oil and products" includes $4,240, $6,735 and $7,063 with affiliated companies for 2015, 2014 and 2013, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $399 and $924 due from affiliated companies at December 31, 2015 and 2014, respectively. "Accounts payable" includes $286 and $345 due to affiliated companies at December 31, 2015 and 2014, 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 $410, $874 and $1,129 at December 31, 2015, 2014 and 2013, respectively.

	Affiliates			Chevron Share		
Year ended December 31	**2015**	2014	2013	**2015**	2014	2013
Total revenues	**$ 71,389**	$ 123,003	$ 131,875	**$ 33,492**	$ 58,937	$ 63,101
Income before income tax expense	**13,129**	20,609	24,075	**6,279**	9,968	11,108
Net income attributable to affiliates	**10,649**	14,758	15,594	**4,691**	7,237	7,845
At December 31						
Current assets	**$ 27,162**	$ 35,662	$ 39,713	**$ 10,657**	$ 13,465	$ 15,156
Noncurrent assets	**71,650**	70,817	68,593	**26,607**	26,053	25,059
Current liabilities	**20,559**	25,308	29,642	**7,351**	9,588	11,587
Noncurrent liabilities	**18,560**	17,983	19,442	**3,909**	4,211	4,559
Total affiliates' net equity	**$ 59,693**	$ 63,188	$ 59,222	**$ 26,004**	$ 25,719	$ 24,069

Note 16
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]		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Upstream												
United States	**$ 93,848**	$ 96,850	$ 89,555	**$ 43,125**	$ 45,864	$ 41,831	**$ 6,586**	$ 9,688	$ 8,188	**$ 8,545**	$ 5,127	$ 4,412
International	**208,395**	192,637	169,623	**127,459**	118,926	104,100	**19,993**	24,920	27,383	**10,803**	9,688	8,336
Total Upstream	**302,243**	289,487	259,178	**170,584**	164,790	145,931	**26,579**	34,608	35,571	**19,348**	14,815	12,748
Downstream												
United States	**23,202**	22,640	22,407	**10,807**	11,019	11,481	**696**	588	1,154	**878**	886	780
International	**9,177**	9,334	9,303	**4,090**	4,219	4,139	**365**	530	653	**355**	396	360
Total Downstream	**32,379**	31,974	31,710	**14,897**	15,238	15,620	**1,061**	1,118	1,807	**1,233**	1,282	1,140
All Other												
United States	**5,500**	5,673	5,402	**2,859**	3,077	3,194	**357**	581	721	**439**	680	286
International	**155**	155	143	**56**	68	84	**5**	25	23	**17**	16	12
Total All Other	**5,655**	5,828	5,545	**2,915**	3,145	3,278	**362**	606	744	**456**	696	298
Total United States	**122,550**	125,163	117,364	**56,791**	59,960	56,506	**7,639**	10,857	10,063	**9,862**	6,693	5,478
Total International	**217,727**	202,126	179,069	**131,605**	123,213	108,323	**20,363**	25,475	28,059	**11,175**	10,100	8,708
Total	**$ 340,277**	$ 327,289	$ 296,433	**$ 188,396**	$ 183,173	$ 164,829	**$ 28,002**	$ 36,332	$ 38,122	**$ 21,037**	$ 16,793	$ 14,186

[1] Other than the United States, Australia and Nigeria, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2015. Australia had $49,205, $41,012 and $31,464 in 2015, 2014, and 2013, respectively. Nigeria had PP&E of $18,773, $19,214 and $18,429 for 2015, 2014 and 2013, respectively.

[2] Net of dry hole expense related to prior years' expenditures of $1,573, $371 and $89 in 2015, 2014 and 2013, respectively.

[3] Depreciation expense includes accretion expense of $715, $882 and $627 in 2015, 2014 and 2013, respectively, and impairments of $4,066, $1,274 and $382 in 2015, 2014 and 2013, respectively.

Note 17
Litigation

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

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously given to Texpet by the Republic of Ecuador and Petroecuador and by the pertinent provincial and municipal governments. With regard to the facts, the company believes that the evidence confirms that Texpet's remediation was properly conducted and that the remaining environmental damage reflects Petroecuador's failure to timely fulfill its legal obligations and Petroecuador's further conduct since assuming full control over the operations.

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

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

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

On July 2, 2013, the provincial court in Lago Agrio issued an embargo order in Ecuador ordering that any funds to be paid by the Government of Ecuador to Chevron to satisfy a $96 award issued in an unrelated action by 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 must be paid to the Lago Agrio plaintiffs. The award was issued by the tribunal under the United States-Ecuador Bilateral Investment Treaty in an action filed in 2006 in connection with seven breach of contract cases that Texpet filed against the Government of Ecuador between 1991 and 1993. The Government of Ecuador has moved to set aside the tribunal's award. On September 26, 2014, the Supreme Court of the Netherlands issued an opinion denying Ecuador's set aside request. A Federal District Court for the District of Columbia confirmed the tribunal's award, and on August 4, 2015, a panel of the U.S. Court of Appeals for the District of Columbia Circuit affirmed the District Court's decision. On September 9, 2015, the Court of Appeals denied the Government of Ecuador's request for full appellate court review of the Federal District Court's decision.

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

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

On October 15, 2012, the provincial court in Lago Agrio issued an ex parte embargo order that purports to order the seizure of assets belonging to separate Chevron subsidiaries in Ecuador, Argentina and Colombia. On November 6, 2012, at the request of the Lago Agrio plaintiffs, a court in Argentina issued a Freeze Order against Chevron Argentina S.R.L. and another Chevron subsidiary, Ingeniero Norberto Priu, requiring shares of both companies to be "embargoed," requiring third parties to withhold 40 percent of any payments due to Chevron Argentina S.R.L. and ordering banks to withhold 40 percent of the funds in Chevron Argentina S.R.L. bank accounts. On December 14, 2012, the Argentinean court rejected a motion to revoke the Freeze Order but modified it by ordering that third parties are not required to withhold funds but must report their payments. The court also clarified that the Freeze Order relating to bank accounts excludes taxes. On January 30, 2013, an appellate court upheld the Freeze Order, but on June 4, 2013 the Supreme Court of Argentina revoked the Freeze Order in its entirety. On December 12, 2013, the Lago Agrio plaintiffs served Chevron with notice of their filing of an enforcement proceeding in the National Court, First Instance, of Argentina. Chevron filed its answer on February 27, 2014, to which the Lago Agrio plaintiffs responded on December 29, 2015.

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

Company's Bilateral Investment Treaty Arbitration Claims Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before an arbitral tribunal presiding in the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador's obligations under the United States–Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador's obligations under the BIT. On February 9, 2011, the Tribunal issued an Order for Interim Measures requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. On January 25, 2012, the Tribunal converted the Order for Interim Measures into an Interim Award. Chevron filed a renewed application for further interim measures on January 4, 2012, and the Republic of Ecuador opposed Chevron's application and requested that the existing Order for Interim Measures be vacated on January 9, 2012. On February 16, 2012, the Tribunal issued a Second Interim Award mandating that the Republic of Ecuador take all measures necessary (whether by its judicial, legislative or executive branches) to suspend or cause to be suspended the enforcement and recognition within and without Ecuador of the judgment against Chevron and, in particular, to preclude any certification by the Republic of Ecuador that would cause the judgment to be enforceable 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.

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

Company's RICO Action Through a series of U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters, alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron is seeking relief that includes 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. On March 7, 2011, the Federal District Court issued a preliminary injunction prohibiting the Lago Agrio plaintiffs and persons acting in concert with them from taking any action in furtherance of recognition or enforcement of any judgment against Chevron in the Lago Agrio case pending resolution of Chevron's civil lawsuit by the Federal District Court. On May 31, 2011, the Federal District Court severed claims one through eight of Chevron's complaint from the ninth claim for declaratory relief and imposed a discovery stay on claims one through eight pending a trial on the ninth claim for declaratory relief. On September 19, 2011, the U.S. Court of Appeals for the Second Circuit vacated the preliminary injunction, stayed the trial on Chevron's ninth claim, a claim for declaratory relief, that had been set for November 14, 2011, and denied the defendants' mandamus petition to recuse the judge hearing the lawsuit. The Second Circuit issued its opinion on January 26, 2012 ordering the dismissal of Chevron's ninth claim for declaratory relief. On February 16, 2012, the Federal District Court lifted the stay on claims one through eight, and on October 18, 2012, the Federal District Court set a trial date of October 15, 2013. On March 22, 2013, Chevron settled its claims against Stratus Consulting, and on April 12, 2013 sworn declarations by representatives of Stratus Consulting were filed with the Court admitting their role and that of the plaintiffs' attorneys in drafting the environmental report of the mining engineer appointed by the provincial court in Lago Agrio. On September 26, 2013, the Second Circuit denied the defendants' Petition for Writ of Mandamus to recuse the judge hearing the case and to collaterally estop Chevron from seeking a declaration that the Lago Agrio judgment was obtained through fraud and other unlawful conduct.

The trial commenced on October 15, 2013 and concluded on November 22, 2013. On March 4, 2014, the Federal District Court entered a judgment in favor of Chevron, prohibiting the defendants from seeking to enforce the Lago Agrio judgment in the United States and further prohibiting them from profiting from their illegal acts. The defendants appealed the Federal District Court's decision, and, on April 20, 2015, a panel of the U.S. Court of Appeals for the Second Circuit heard oral arguments.

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

Note 18
Taxes

Income Taxes			Year ended December 31
	2015	2014	2013
Income tax expense (benefit)			
U.S. federal			
Current	**$ (817)**	$ 748	$ 15
Deferred	**(580)**	1,330	1,128
State and local			
Current	**(187)**	336	120
Deferred	**(109)**	36	74
Total United States	**(1,693)**	2,450	1,337
International			
Current	**2,997**	9,235	12,296
Deferred	**(1,172)**	207	675
Total International	**1,825**	9,442	12,971
Total income tax expense (benefit)	**$ 132**	$ 11,892	$ 14,308

In 2015, before-tax loss for U.S. operations, including related corporate and other charges, was $(2,877), compared with before-tax income of $6,296 and $4,672 in 2014 and 2013, respectively. For international operations, before-tax income was $7,719, $24,906 and $31,233 in 2015, 2014 and 2013, respectively. U.S. federal income tax expense was reduced by $35, $68 and $175 in 2015, 2014 and 2013, respectively, for business tax credits.

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:

	Year ended December 31		
	2015	2014	2013
U.S. statutory federal income tax rate	**35.0 %**	35.0 %	35.0 %
Effect of income taxes from international operations[1]	**(25.1)**	2.1	4.4
State and local taxes on income, net of U.S. federal income tax benefit	**(1.5)**	0.7	0.6
Tax credits	**(0.7)**	(0.2)	(0.5)
Other[1,2]	**(5.0)**	0.5	0.4
Effective tax rate	**2.7 %**	38.1 %	39.9 %

[1] 2013 and 2014 conformed to 2015 presentation.
[2] 2015 includes one-time tax benefits associated with changes in uncertain tax positions and provision-to-return adjustments.

The company's effective tax rate decreased from 38.1 percent in 2014 to 2.7 percent in 2015. The decrease primarily resulted from the impacts of jurisdictional mix, one-time tax benefits, foreign currency remeasurement, equity earnings and a reduction in statutory tax rates in the United Kingdom, partially offset by the effects of valuation allowances recognized on deferred tax assets and the sale of the company's interest in Caltex Australia Limited.

The company records its deferred taxes on a tax-jurisdiction basis and classifies those net amounts as current or noncurrent based on the balance sheet classification of the related assets or liabilities. The reported deferred tax balances are composed of the following:

	At December 31	
	2015	2014
Deferred tax liabilities		
Properties, plant and equipment	**$ 27,044**	$ 28,452
Investments and other	**3,743**	3,059
Total deferred tax liabilities	**30,787**	31,511
Deferred tax assets		
Foreign tax credits	**(10,534)**	(11,867)
Abandonment/environmental reserves	**(6,880)**	(6,686)
Employee benefits	**(4,801)**	(4,831)
Deferred credits	**(1,810)**	(1,828)
Tax loss carryforwards	**(2,748)**	(1,747)
Other accrued liabilities	**(525)**	(498)
Inventory	**(120)**	(153)
Miscellaneous	**(2,525)**	(2,128)
Total deferred tax assets	**(29,943)**	(29,738)
Deferred tax assets valuation allowance	**15,412**	16,292
Total deferred taxes, net	**$ 16,256**	$ 18,065

Deferred tax liabilities at the end of 2015 decreased by approximately $700 from year-end 2014. The decrease was primarily related to decreased temporary differences related to property, plant and equipment. Deferred tax assets were essentially unchanged between periods. A reduction in U.S. foreign tax credits was substantially offset by an increase in foreign 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 2015, the company had tax loss carryforwards of approximately $7,615 and tax credit carryforwards of approximately $1,249, 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 2016 through 2025. U.S. foreign tax credit carryforwards of $10,534 will expire between 2017 and 2024.

At December 31, 2015 and 2014, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2015	2014
Prepaid expenses and other current assets	**$ (917)**	$ (1,071)
Deferred charges and other assets	**(4,512)**	(3,597)
Federal and other taxes on income	**996**	813
Noncurrent deferred income taxes	**20,689**	21,920
Total deferred income taxes, net	**16,256**	$ 18,065

Income 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 $45,400 at December 31, 2015. This amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the possible remittance of earnings that are intended to be reinvested indefinitely. At the end of 2015, deferred income taxes were recorded for the undistributed earnings of certain international operations where indefinite reinvestment of the earnings is not planned. 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, 2015, 2014 and 2013. 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.

	2015	2014	2013
Balance at January 1	**$ 3,552**	$ 3,848	$ 3,071
Foreign currency effects	**(27)**	(25)	(58)
Additions based on tax positions taken in current year	**154**	354	276
Additions/reductions resulting from current-year asset acquisitions/sales	**—**	(22)	—
Additions for tax positions taken in prior years	**218**	37	1,164
Reductions for tax positions taken in prior years	**(678)**	(561)	(176)
Settlements with taxing authorities in current year	**(5)**	(50)	(320)
Reductions as a result of a lapse of the applicable statute of limitations	**(172)**	(29)	(109)
Balance at December 31	**$ 3,042**	$ 3,552	$ 3,848

The decrease in unrecognized tax benefits between December 31, 2014, and December 31, 2015 was primarily due to the resolution of numerous audit issues with various tax jurisdictions during the year.

Approximately 71 percent of the $3,042 of unrecognized tax benefits at December 31, 2015, 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, 2015. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2011, Nigeria – 2000, Angola – 2009, Saudi Arabia – 2012 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, 2015, accruals of $399 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $233 as of year-end 2014. Income tax expense (benefit) associated with interest and penalties was $195, $4 and $(42) in 2015, 2014 and 2013, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2015	2014	2013
United States			
Excise and similar taxes on products and merchandise	**$ 4,426**	$ 4,633	$ 4,792
Import duties and other levies	**4**	6	4
Property and other miscellaneous taxes	**1,367**	1,002	1,036
Payroll taxes	**270**	273	255
Taxes on production	**157**	349	333
Total United States	**6,224**	6,263	6,420
International			
Excise and similar taxes on products and merchandise	**2,933**	3,553	3,700
Import duties and other levies	**40**	45	41
Property and other miscellaneous taxes	**2,548**	2,277	2,486
Payroll taxes	**161**	172	168
Taxes on production	**124**	230	248
Total International	**5,806**	6,277	6,643
Total taxes other than on income	**$ 12,030**	$ 12,540	$ 13,063

Note 19
Short-Term Debt

	At December 31	
	2015	2014
Commercial paper*	**$ 8,252**	$ 8,506
Notes payable to banks and others with originating terms of one year or less	**20**	104
Current maturities of long-term debt	**1,487**	—
Current maturities of long-term capital leases	**17**	22
Redeemable long-term obligations		
Long-term debt	**3,152**	3,152
Capital leases	**—**	6
Subtotal	**12,928**	11,790
Reclassified to long-term debt	**(8,000)**	(8,000)
Total short-term debt	**$ 4,928**	$ 3,790

* Weighted-average interest rates at December 31, 2015 and 2014, were 0.26 percent and 0.12 percent, respectively.

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, 2015, the company had no interest rate swaps on short-term debt.

At December 31, 2015, the company had $8,000 in committed credit facilities with various major banks that enable the refinancing of short-term obligations on a long-term basis. The credit facilities consist of a 364-day facility which enables borrowing of up to $6,000 and can be renewed for an additional 364-day period or the company can convert any amounts outstanding into a term loan for a period of up to one year, and a $2,000 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, 2015.

At both December 31, 2015 and 2014, the company classified $8,000 of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital within one year, and the company has both the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Note 20
Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2015, was $33,584. The company's long-term debt outstanding at year-end 2015 and 2014 was as follows:

	At December 31	
	2015	2014
3.191% notes due 2023	**$ 2,250**	$ 2,250
Floating rate notes due 2017 (0.555%)[1]	**2,050**	650
1.104% notes due 2017	**2,000**	2,000
1.718% notes due 2018	**2,000**	2,000
2.355% notes due 2022	**2,000**	2,000
1.365% notes due 2018	**1,750**	—
1.961% notes due 2020	**1,750**	—
4.95% notes due 2019	**1,500**	1,500
1.790% notes due 2018	**1,250**	—
2.419% notes due 2020	**1,250**	—
1.345% notes due 2017	**1,100**	1,100
1.344% notes due 2017	**1,000**	—
2.427% notes due 2020	**1,000**	1,000
Floating rate notes due 2018 (0.676%)[1]	**800**	—
0.889% notes due 2016	**750**	750
2.193% notes due 2019	**750**	750
3.326% notes due 2025	**750**	—
2.411% notes due 2022	**700**	—
Floating rate notes due 2016 (0.444%)[2]	**700**	700
Floating rate notes due 2019 (0.772%)[2]	**400**	400
Floating rate notes due 2021 (0.892%)[2]	**400**	400
Floating rate notes due 2022 (0.952%)[2]	**350**	—
8.625% debentures due 2032	**147**	147
Amortizing Bank Loan due 2018 (1.172%)[2]	**110**	—
8.625% debentures due 2031	**108**	107
8.0% debentures due 2032	**74**	74
9.75% debentures due 2020	**54**	54
8.875% debentures due 2021	**40**	40
Medium-term notes, maturing from 2021 to 2038 (5.975%)[1]	**38**	38
Total including debt due within one year	**27,071**	15,960
Debt due within one year	**(1,487)**	—
Reclassified from short-term debt	**8,000**	8,000
Total long-term debt	**$ 33,584**	$ 23,960

1 Weighted-average interest rate at December 31, 2015.
2 Interest rate at December 31, 2015.

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

Long-term debt of $27,071 matures as follows: 2016 – $1,487; 2017 – $6,187; 2018 – $5,836; 2019 – $2,650; 2020 – $4,054; and after 2020 – $6,857.

The company completed bond issuances of $6,000 and $5,000 in March and November 2015, respectively.

See Note 9, beginning on page 42, for information concerning the fair value of the company's long-term debt.

Note 21
Accounting for Suspended Exploratory Wells

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

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2015:

	2015	2014	2013
Beginning balance at January 1	**$ 4,195**	$ 3,245	$ 2,681
Additions to capitalized exploratory well costs pending the determination of proved reserves	**869**	1,591	885
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(164)**	(298)	(290)
Capitalized exploratory well costs charged to expense	**(1,397)**	(312)	(31)
Other reductions*	**(191)**	(31)	—
Ending balance at December 31	**$ 3,312**	$ 4,195	$ 3,245

* 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		
	2015	2014	2013
Exploratory well costs capitalized for a period of one year or less	**$ 489**	$ 1,522	$ 641
Exploratory well costs capitalized for a period greater than one year	**2,823**	2,673	2,604
Balance at December 31	**$ 3,312**	$ 4,195	$ 3,245
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**39**	51	51

* Certain projects have multiple wells or fields or both.

Of the $2,823 of exploratory well costs capitalized for more than one year at December 31, 2015, $1,662 (20 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $1,161 balance is related to 19 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way 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 $1,161 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $190 (two projects) – undergoing front-end engineering and design with final investment decision expected within four years; (b) $99 (one project) – development concept under review by government; (c) $814 (seven projects) – development alternatives under review; (d) $58 (nine projects) – miscellaneous activities for projects with smaller amounts suspended. While progress was being made on all 39 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. Approximately half of these decisions are expected to occur in the next five years.

The $2,823 of suspended well costs capitalized for a period greater than one year as of December 31, 2015, represents 165 exploratory wells in 39 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
1998–2004	$ 285	26
2005–2009	395	33
2010–2014	2,143	106
Total	$ 2,823	165

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
2003–2007	$ 200	4
2008–2011	393	6
2012–2015	2,230	29
Total	$ 2,823	39

Note 22

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2015, 2014 and 2013 was $312 ($203 after tax), $287 ($186 after tax) and $292 ($190 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was $32 ($21 after tax), $71 ($46 after tax) and $223 ($145 after tax) for 2015, 2014 and 2013, respectively. No significant stock-based compensation cost was capitalized at December 31, 2015, or December 31, 2014.

Cash received in payment for option exercises under all share-based payment arrangements for 2015, 2014 and 2013 was $195, $527 and $553, respectively. Actual tax benefits realized for the tax deductions from option exercises were $17, $54 and $73 for 2015, 2014 and 2013, respectively.

Cash paid to settle performance units and stock appreciation rights was $104, $204 and $186 for 2015, 2014 and 2013, 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 units 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 outstanding as of December 31, 2015, the contractual terms vary between three years for the performance units and restricted stock units, and 10 years for the stock options and stock appreciation rights.

Remaining awards under the Unocal Share-Based Plans expired in early 2015.

The fair market values of stock options and stock appreciation rights granted in 2015, 2014 and 2013 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2015	2014	2013
Expected term in years[1]	**6.1**	6.0	6.0
Volatility[2]	**21.9 %**	30.3 %	31.3 %
Risk-free interest rate based on zero coupon U.S. treasury note	**1.4 %**	1.9 %	1.2 %
Dividend yield	**3.6 %**	3.3 %	3.3 %
Weighted-average fair value per option granted	**$ 13.89**	$ 25.86	$ 24.48

[1] Expected term is based on historical exercise and postvesting cancellation data.
[2] Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

A summary of option activity during 2015 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Averaged Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at January 1, 2015	78,341	$ 93.59		
Granted	22,126	$ 103.71		
Exercised	(3,104)	$ 62.06		
Forfeited	(3,071)	$ 103.70		
Outstanding at December 31, 2015	94,292	$ 96.67	5.83	$ 467
Exercisable at December 31, 2015	65,657	$ 91.85	4.61	$ 467

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2015, 2014 and 2013 was $120, $398 and $445, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2015, there was $190 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted under the plans. That cost is expected to be recognized over a weighted-average period of 1.7 years.

At January 1, 2015, the number of LTIP performance units outstanding was equivalent to 2,265,952 shares. During 2015, 890,000 units were granted, 828,868 units vested with cash proceeds distributed to recipients and 134,147 units were forfeited. At December 31, 2015, units outstanding were 2,192,937. The fair value of the liability recorded for these instruments was $166, and was measured using the Monte Carlo simulation method. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP programs totaled approximately 4.5 million equivalent shares as of December 31, 2015. A liability of $51 was recorded for these awards.

Note 23
Employee Benefit Plans

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

The company also sponsors other postretirement benefit (OPEB) plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and retirees share the costs. Medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the 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 2015 and 2014 follows:

	Pension Benefits				Other Benefits	
	2015		2014			
	U.S.	**Int'l.**	U.S.	Int'l.	**2015**	2014
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 14,250**	**$ 5,767**	$ 12,080	$ 6,095	**$ 3,660**	$ 3,138
Service cost	**538**	**185**	450	190	**72**	50
Interest cost	**502**	**277**	494	340	**151**	148
Plan participants' contributions	**—**	**6**	—	8	**148**	150
Plan amendments	**—**	**(6)**	—	3	**—**	2
Actuarial (gain) loss	**(345)**	**(309)**	2,299	336	**(326)**	544
Foreign currency exchange rate changes	**—**	**(326)**	—	(348)	**(37)**	(22)
Benefits paid	**(1,382)**	**(241)**	(1,073)	(293)	**(344)**	(350)
Divestitures	**—**	**—**	—	(564)	**—**	—
Curtailment	**—**	**(17)**	—	—	**—**	—
Benefit obligation at December 31	**13,563**	**5,336**	14,250	5,767	**3,324**	3,660
Change in Plan Assets						
Fair value of plan assets at January 1	**11,090**	**4,244**	11,210	4,543	**—**	—
Actual return on plan assets	**(75)**	**112**	854	571	**—**	—
Foreign currency exchange rate changes	**—**	**(239)**	—	(279)	**—**	—
Employer contributions	**641**	**227**	99	276	**196**	200
Plan participants' contributions	**—**	**6**	—	8	**148**	150
Benefits paid	**(1,382)**	**(241)**	(1,073)	(293)	**(344)**	(350)
Divestitures	**—**	**—**	—	(582)	**—**	—
Fair value of plan assets at December 31	**10,274**	**4,109**	11,090	4,244	**—**	—
Funded Status at December 31	**$ (3,289)**	**$ (1,227)**	$ (3,160)	$ (1,523)	**$ (3,324)**	$ (3,660)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and OPEB plans at December 31, 2015 and 2014, include:

	Pension Benefits				Other Benefits	
	2015		2014			
	U.S.	**Int'l.**	U.S.	Int'l.	**2015**	2014
Deferred charges and other assets	**$ 13**	**$ 333**	$ 13	$ 244	**$ —**	$ —
Accrued liabilities	**(153)**	**(77)**	(123)	(68)	**(191)**	(198)
Noncurrent employee benefit plans	**(3,149)**	**(1,483)**	(3,050)	(1,699)	**(3,133)**	(3,462)
Net amount recognized at December 31	**$ (3,289)**	**$ (1,227)**	$ (3,160)	$ (1,523)	**$ (3,324)**	$ (3,660)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were $6,478 and $7,417 at the end of 2015 and 2014, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2015		2014			
	U.S.	**Int'l.**	U.S.	Int'l.	**2015**	2014
Net actuarial loss	**$ 4,809**	**$ 1,143**	$ 4,972	$ 1,487	**$ 367**	$ 763
Prior service (credit) costs	**(5)**	**120**	(13)	150	**44**	58
Total recognized at December 31	**$ 4,804**	**$ 1,263**	$ 4,959	$ 1,637	**$ 411**	$ 821

The accumulated benefit obligations for all U.S. and international pension plans were $12,032 and $4,684, respectively, at December 31, 2015, and $12,833 and $4,995, respectively, at December 31, 2014.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2015 and 2014, was:

	Pension Benefits			
	2015		2014	
	U.S.	**Int'l.**	U.S.	Int'l.
Projected benefit obligations	**$ 13,500**	**$ 1,623**	$ 14,182	$ 1,938
Accumulated benefit obligations	**11,969**	**1,357**	12,765	1,525
Fair value of plan assets	**10,198**	**207**	11,009	262

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2015, 2014 and 2013 are shown in the table below:

	Pension Benefits						Other Benefits		
	2015		2014		2013				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2015**	2014	2013
Net Periodic Benefit Cost									
Service cost	**$ 538**	**$ 185**	$ 450	$ 190	$ 495	$ 197	**$ 72**	$ 50	$ 66
Interest cost	**502**	**277**	494	340	471	314	**151**	148	149
Expected return on plan assets	**(783)**	**(262)**	(788)	(298)	(701)	(274)	**—**	—	—
Amortization of prior service costs (credits)	**(8)**	**22**	(9)	21	2	21	**14**	14	(50)
Recognized actuarial losses	**356**	**78**	209	96	485	143	**34**	7	53
Settlement losses	**320**	**6**	237	208	173	12	**—**	—	—
Curtailment losses (gains)	**—**	**(14)**	—	—	—	—	**—**	—	—
Total net periodic benefit cost	**925**	**292**	593	557	925	413	**271**	219	218
Changes Recognized in Comprehensive Income									
Net actuarial (gain) loss during period	**513**	**(260)**	2,233	(17)	(2,244)	(476)	**(362)**	514	(659)
Amortization of actuarial loss	**(676)**	**(84)**	(446)	(304)	(658)	(155)	**(34)**	(7)	(53)
Prior service (credits) costs during period	**—**	**(6)**	—	4	(78)	18	**—**	2	—
Amortization of prior service (costs) credits	**8**	**(24)**	9	(21)	(2)	(21)	**(14)**	(14)	50
Total changes recognized in other comprehensive income	**(155)**	**(374)**	1,796	(338)	(2,982)	(634)	**(410)**	495	(662)
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 770**	**$ (82)**	$2,389	$ 219	$(2,057)	$ (221)	**$ (139)**	$ 714	$ (444)

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2015, for the company's U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 10, 10 and 16 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 2016, the company estimates actuarial losses of $335, $56 and $19 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 $324 will be recognized from "Accumulated other comprehensive loss" during 2016 related to lump-sum settlement costs from the main U.S. pension plan.

The weighted average amortization period for recognizing prior service costs (credits) recorded in "Accumulated other comprehensive loss" at December 31, 2015, was approximately 4 and 11 years for U.S. and international pension plans, respectively, and 7 years for OPEB plans. During 2016, the company estimates prior service (credits) costs of $(9), $15 and $14 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		
	2015		2014		2013				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2015**	2014	2013
Assumptions used to determine benefit obligations:									
Discount rate	**4.0%**	**5.3%**	3.7%	5.0%	4.3%	5.8%	**4.6%**	4.3%	4.9%
Rate of compensation increase	**4.5%**	**4.8%**	4.5%	5.1%	4.5%	5.5%	**N/A**	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate	**3.7%**	**5.0%**	4.3%	5.8%	3.6%	5.2%	**4.3%**	4.9%	4.1%
Expected return on plan assets	**7.5%**	**6.3%**	7.5%	6.6%	7.5%	6.8%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**5.1%**	4.5%	5.5%	4.5%	5.5%	**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 2015, the company used an expected long-term rate of return of 7.5 percent for U.S. pension plan assets, which account for 71 percent of the company's pension plan assets. In both 2014 and 2013, the company used a long-term rate of return of 7.5 percent for this plan.

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. At December 31, 2015, 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 were 4.0 percent for the main U.S. pension plan and 4.5 percent for the main U.S. OPEB plan. The discount rates for these plans at the end of 2014 were 3.7 and 4.1 percent, respectively, while in 2013 they were 4.3 and 4.7 percent for these plans, respectively.

The company changed the method used to estimate the service and interest costs associated with the company's main U.S. pension and OPEB plans. In prior years, the service and interest costs were estimated utilizing a single weighted-average discount rate derived from the yield curve used to measure the defined benefit obligations at the beginning of the year. Under the new method, these costs are estimated by applying spot rates along the yield curve to the relevant projected cash flows. The change was made to provide a more precise measurement of the service and interest costs by improving the correlation between projected benefit cash flows and the corresponding spot yield curve rates. This change in accounting estimate is accounted for prospectively beginning with the year ending December 31, 2016. The company does not expect the change to have a material effect on its consolidated financial position or liquidity.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2015, for the main U.S. OPEB plan, the assumed health care cost-trend rates start with 7.1 percent in 2016 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2014, the assumed health care cost-trend rates started with 7 percent in 2015 and gradually declined to 4.5 percent for 2025 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company's medical contributions for the main U.S. plan. 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	$ 20	$ (17)
Effect on postretirement benefit obligation	$ 192	$ (164)

Plan Assets and Investment Strategy

The fair value measurements of the company's pension plans for 2015 and 2014 are below:

	U.S.				Int'l.			
	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
At December 31, 2014								
Equities								
U.S.[1]	$ 2,087	$ 2,087	$ —	$ —	$ 241	$ 241	$ —	$ —
International	1,297	1,297	—	—	313	313	—	—
Collective Trusts/Mutual Funds[2]	3,240	22	3,218	—	979	173	806	—
Fixed Income								
Government	84	47	37	—	1,066	53	1,013	—
Corporate	1,502	—	1,502	—	585	26	537	22
Mortgage-Backed Securities	1	—	1	—	1	—	1	—
Other Asset Backed	—	—	—	—	—	—	—	—
Collective Trusts/Mutual Funds[2]	1,174	—	1,174	—	394	16	378	—
Mixed Funds[3]	—	—	—	—	122	3	119	—
Real Estate[4]	1,364	—	—	1,364	329	—	—	329
Cash and Cash Equivalents	270	270	—	—	190	189	1	—
Other[5]	71	(3)	20	54	24	—	21	3
Total at December 31, 2014	$ 11,090	$ 3,720	$ 5,952	$ 1,418	$ 4,244	$ 1,014	$ 2,876	$ 354
At December 31, 2015								
Equities								
U.S.[1]	**$ 1,699**	**$ 1,699**	**$ —**	**$ —**	**$ 392**	**$ 382**	**$ 10**	**$ —**
International	**1,302**	**1,296**	**6**	**—**	**457**	**435**	**22**	**—**
Collective Trusts/Mutual Funds[2]	**2,460**	**18**	**2,442**	**—**	**572**	**7**	**565**	**—**
Fixed Income								
Government	**257**	**46**	**211**	**—**	**1,089**	**93**	**996**	**—**
Corporate	**1,654**	**—**	**1,654**	**—**	**615**	**33**	**557**	**25**
Bank Loans	**148**	**—**	**148**	**—**	**—**	**—**	**—**	**—**
Mortgage-Backed Securities	**1**	**—**	**1**	**—**	**1**	**—**	**1**	**—**
Other Asset Backed	**1**	**—**	**1**	**—**	**—**	**—**	**—**	**—**
Collective Trusts/Mutual Funds[2]	**933**	**—**	**933**	**—**	**269**	**12**	**257**	**—**
Mixed Funds[3]	**—**	**—**	**—**	**—**	**85**	**4**	**81**	**—**
Real Estate[4]	**1,494**	**—**	**—**	**1,494**	**378**	**—**	**—**	**378**
Cash and Cash Equivalents	**253**	**253**	**—**	**—**	**232**	**232**	**—**	**—**
Other[5]	**72**	**(6)**	**26**	**52**	**19**	**(2)**	**19**	**2**
Total at December 31, 2015	**$ 10,274**	**$ 3,306**	**$ 5,422**	**$ 1,546**	**$ 4,109**	**$ 1,196**	**$ 2,508**	**$ 405**

1 U.S. equities include investments in the company's common stock in the amount of $9 at December 31, 2015, and $24 at December 31, 2014.
2 Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is partially based on the restriction that advance notification of redemptions, typically two business days, is required.
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 internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.
5 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 and investments in private-equity limited partnerships (Level 3).

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

	Fixed Income				
	Corporate	Mortgage-Backed Securities	Real Estate	Other	Total
Total at December 31, 2013	$ 23	$ 2	$ 1,559	$ 57	$ 1,641
Actual Return on Plan Assets:					
Assets held at the reporting date	—	—	115	—	115
Assets sold during the period	—	—	20	—	20
Purchases, Sales and Settlements	(1)	(2)	(1)	—	(4)
Transfers in and/or out of Level 3	—	—	—	—	—
Total at December 31, 2014	$ 22	$ —	$ 1,693	$ 57	$ 1,772
Actual Return on Plan Assets:					
Assets held at the reporting date	**(3)**	**—**	**149**	**(1)**	**145**
Assets sold during the period	**—**	**—**	**23**	**—**	**23**
Purchases, Sales and Settlements	**6**	**—**	**7**	**(2)**	**11**
Transfers in and/or out of Level 3	**—**	**—**	**—**	**—**	**—**
Total at December 31, 2015	**$ 25**	**$ —**	**$ 1,872**	**$ 54**	**$ 1,951**

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 Benefit Plan Investment Committee has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income and Cash 20–60 percent, Real Estate 0–15 percent, and Other 0–5 percent. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines: Equities 30–50 percent, Fixed Income and Cash 35–65 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 current economic and market conditions and consideration of specific asset class risk. 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 2015, the company contributed $641 and $227 to its U.S. and international pension plans, respectively. In 2016, the company expects contributions to be approximately $650 to its U.S. plans and $250 to its international pension plans. Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments 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 $191 in 2016; $196 was paid in 2015.

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
2016	$ 1,462	$ 284	$ 191
2017	$ 1,384	$ 297	$ 195
2018	$ 1,360	$ 467	$ 199
2019	$ 1,329	$ 339	$ 203
2020	$ 1,287	$ 346	$ 207
2021-2025	$ 5,804	$ 1,822	$ 1,053

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP). Compensation expense for the ESIP totaled $316, $316 and $163 in 2015, 2014 and 2013, respectively. The amount for ESIP expense in 2013 is net of $140, which reflects the value of common stock released from the former leveraged employee stock ownership plan (LESOP). LESOP debt was retired in 2013, and all remaining shares were released.

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 2015, 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, 2015 and 2014, trust assets of $36 and $38, 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 $690, $965 and $871 in 2015, 2014 and 2013, respectively. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 22, beginning on page 58.

Note 24

Other Contingencies and Commitments

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 18, beginning on page 53, 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 provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees The company's guarantee of $447 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 12-year remaining term of the 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 its obligation under this guarantee.

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

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2016 – $2,100; 2017 – $1,900; 2018 – $1,700; 2019 – $1,500; 2020 – $1,100; 2020 and after – $3,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $1,900 in 2015, $3,700 in 2014 and $3,600 in 2013.

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, 2015, was $1,578. Included in this balance were $348 related to remediation activities at approximately 163 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 2015 environmental reserves balance of $1,230, $845 is related to the company's U.S. downstream operations, $58 to its international downstream operations, $323 to upstream operations and $4 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 2015 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

Refer to Note 25 on page 67 for a discussion of the company's asset retirement obligations.

Other Contingencies On November 7, 2011, while drilling a development well in the deepwater Frade Field about 75 miles offshore Brazil, an unanticipated pressure spike caused oil to migrate from the well bore through a series of fissures to the sea floor, emitting approximately 2,400 barrels of oil. The source of the seep was substantially contained within four days and the well was plugged and abandoned. On March 14, 2012, the company identified a small, second seep in a different part of the field. No evidence of any coastal or wildlife impacts related to either of these seeps emerged. As reported in the company's previously filed periodic reports, it has resolved civil claims relating to these incidents brought by a Brazilian federal district prosecutor. As also reported previously, the federal district prosecutor also filed criminal charges against Chevron and 11 Chevron employees. These charges were dismissed by the trial court on February 19, 2013, reinstated by an appellate court on October 9, 2013, and then, upon Chevron's motion for reconsideration, dismissed by the appellate court on August 27, 2015. The federal district prosecutor has appealed the appellate court's decision.

Chevron receives claims from and submits claims to customers; trading 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 25

Asset Retirement Obligations

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

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

The following table indicates the changes to the company's before-tax asset retirement obligations in 2015, 2014 and 2013:

	2015	2014	2013
Balance at January 1	**$ 15,053**	$ 14,298	$ 13,271
Liabilities incurred	**51**	133	59
Liabilities settled	**(981)**	(1,291)	(907)
Accretion expense	**715**	882	627
Revisions in estimated cash flows	**804**	1,031	1,248
Balance at December 31	**$ 15,642**	$ 15,053	$ 14,298

In the table above, the amounts associated with "Revisions in estimated cash flows" generally reflect increased cost estimates to abandon wells, equipment and facilities and accelerated timing of abandonment. The long-term portion of the $15,642 balance at the end of 2015 was $14,892.

Note 26

Restructuring and Reorganization Costs

In 2015, the company recorded accruals and adjustments for employee reduction programs related to the restructuring and reorganization of its corporate staffs and certain upstream operations. The employee reductions are expected to be substantially completed by the end of 2016.

A before-tax charge of $353 ($223 after-tax) was recorded in 2015, with $219 reported as "Operating Expenses" and $134 reported as "Selling, general and administrative expense" on the Consolidated Statement of Income. The accrued liability, covering severance benefits, is classified as current on the Consolidated Balance Sheet. Approximately $134 ($87 after-tax) is associated with employee reductions in All Other, $113 ($73 after-tax) in U.S. Upstream and $106 ($63 after-tax) in International Upstream.

During 2015, the company made payments of $60 associated with these liabilities. The following table summarizes the accrued severance liability, which is classified as current on the Consolidated Balance Sheet:

	Amounts Before Tax
Balance at January 1, 2015	$ —
Accruals/Adjustments	**353**
Payments	**(60)**
Balance at December 31, 2015	**$ 293**

Note 27

Other Financial Information

Earnings in 2015 included after-tax gains of approximately $2,300 relating to the sale of nonstrategic properties. Of this amount, approximately $1,800 and $500 related to downstream and upstream, respectively. Earnings in 2014 included after-tax gains of approximately $3,000 relating to the sale of nonstrategic properties, of which approximately $1,800 and $1,000 related to upstream and downstream assets, respectively. Earnings in 2015 included after-tax charges of approximately $3,000 for impairments and other asset write-offs related to upstream. Earnings in 2014 included after-tax charges of approximately $1,000 for impairments and other asset write-offs, of which $800 was related to upstream and $200 to a mining asset.

Other financial information is as follows:

	Year ended December 31		
	2015	2014	2013
Total financing interest and debt costs	**$ 495**	$ 358	$ 284
Less: Capitalized interest	**495**	358	284
Interest and debt expense	**$ —**	$ —	$ —
Research and development expenses	**$ 601**	$ 707	$ 750
Excess of replacement cost over the carrying value of inventories (LIFO method)	**3,745**	8,135	9,150
LIFO (losses) / profits on inventory drawdowns included in earnings	**(65)**	13	14
Foreign currency effects*	**$ 769**	$ 487	$ 474

* Includes $344, $118 and $244 in 2015, 2014 and 2013, respectively, for the company's share of equity affiliates' foreign currency effects.

The company has $4,588 in goodwill on the Consolidated Balance Sheet related to the 2005 acquisition of Unocal and to the 2011 acquisition of Atlas Energy, Inc. The company tested this goodwill for impairment during 2015 and concluded no impairment was necessary.

Five-Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts	**2015**	2014	2013	2012	2011
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	**$ 129,925**	$ 200,494	$ 220,156	$ 230,590	$ 244,371
Income from equity affiliates and other income	**8,552**	11,476	8,692	11,319	9,335
Total Revenues and Other Income	**138,477**	211,970	228,848	241,909	253,706
Total Costs and Other Deductions	**133,635**	180,768	192,943	195,577	206,072
Income Before Income Tax Expense	**4,842**	31,202	35,905	46,332	47,634
Income Tax Expense	**132**	11,892	14,308	19,996	20,626
Net Income	**4,710**	19,310	21,597	26,336	27,008
Less: Net income attributable to noncontrolling interests	**123**	69	174	157	113
Net Income Attributable to Chevron Corporation	**$ 4,587**	$ 19,241	$ 21,423	$ 26,179	$ 26,895
Per Share of Common Stock					
Net Income Attributable to Chevron					
– Basic	**$ 2.46**	$ 10.21	$ 11.18	$ 13.42	$ 13.54
– Diluted	**$ 2.45**	$ 10.14	$ 11.09	$ 13.32	$ 13.44
Cash Dividends Per Share	**$ 4.28**	$ 4.21	$ 3.90	$ 3.51	$ 3.09
Balance Sheet Data (at December 31)					
Current assets	**$ 35,347**	$ 42,232	$ 50,250	$ 55,720	$ 53,234
Noncurrent assets	**230,756**	223,794	203,503	177,262	156,240
Total Assets	**266,103**	266,026	253,753	232,982	209,474
Short-term debt	**4,928**	3,790	374	127	340
Other current liabilities	**21,536**	28,136	32,644	34,085	33,260
Long-term debt and capital lease obligations	**33,664**	24,028	20,057	12,065	9,812
Other noncurrent liabilities	**52,089**	53,881	50,251	48,873	43,881
Total Liabilities	**112,217**	109,835	103,326	95,150	87,293
Total Chevron Corporation Stockholders' Equity	**$ 152,716**	$ 155,028	$ 149,113	$ 136,524	$ 121,382
Noncontrolling interests	**1,170**	1,163	1,314	1,308	799
Total Equity	**$ 153,886**	$ 156,191	$ 150,427	$ 137,832	$ 122,181
* Includes excise, value-added and similar taxes:	**$ 7,359**	$ 8,186	$ 8,492	$ 8,010	$ 8,085

Five-Year Operating Summary

Unaudited

Worldwide – Includes Equity in Affiliates *Thousands of barrels per day, except natural gas data, which is millions of cubic feet per day*	**2015**	2014	2013	2012	2011
United States					
Net production of crude oil and natural gas liquids	**501**	456	449	455	465
Net production of natural gas[1]	**1,310**	1,250	1,246	1,203	1,279
Net oil-equivalent production	**720**	664	657	655	678
Refinery input	**924**	871	774	833	854
Sales of refined products	**1,228**	1,210	1,182	1,211	1,257
Sales of natural gas liquids	**153**	141	142	157	161
Total sales of petroleum products	**1,381**	1,351	1,324	1,368	1,418
Sales of natural gas	**3,913**	3,995	5,483	5,470	5,836
International					
Net production of crude oil and natural gas liquids[2]	**1,243**	1,253	1,282	1,309	1,384
Net production of natural gas[1]	**3,959**	3,917	3,946	3,871	3,662
Net oil-equivalent production	**1,902**	1,907	1,940	1,955	1,995
Refinery input[3]	**778**	819	864	869	933
Sales of refined products[4]	**1,507**	1,501	1,529	1,554	1,692
Sales of natural gas liquids	**89**	86	88	88	87
Total sales of petroleum products	**1,596**	1,587	1,617	1,642	1,779
Sales of natural gas	**4,299**	4,304	4,251	4,315	4,361
Total Worldwide					
Net production of crude oil and natural gas liquids	**1,744**	1,709	1,731	1,764	1,849
Net production of natural gas	**5,269**	5,167	5,192	5,074	4,941
Net oil-equivalent production	**2,622**	2,571	2,597	2,610	2,673
Refinery input	**1,702**	1,690	1,638	1,702	1,787
Sales of refined products	**2,735**	2,711	2,711	2,765	2,949
Sales of natural gas liquids	**242**	227	230	245	248
Total sales of petroleum products	**2,977**	2,938	2,941	3,010	3,197
Sales of natural gas	**8,212**	8,299	9,734	9,785	10,197
Worldwide – Excludes Equity in Affiliates					
Number of completed wells (net)[5, 6]					
Oil and gas	**1,848**	2,248	1,833	1,618	1,551
Dry	**18**	28	20	19	19
Productive oil and gas wells (net)[5, 6]	**57,454**	56,204	56,635	55,812	55,049

[1] Includes natural gas consumed in operations:					
United States	**66**	71	72	65	69
International	**430**	452	458	457	447
[2] Includes net production of synthetic oil:					
Canada	**47**	43	43	43	40
Venezuela affiliate	**29**	31	25	17	32
[3] As of June 2012, Star Petroleum Refining Public Company Limited crude-input volumes are reported on a 100 percent consolidated basis. Prior to June 2012, crude-input volumes reflect a 64 percent equity interest.					
[4] Includes sales of affiliates (MBPD):	**420**	475	471	522	556
[5] Net wells include wholly owned and the sum of fractional interests in partially owned wells					
[6] 2014 conformed to 2015 presentation					

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 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

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, 2015									
Exploration									
Wells	**$ 857**	**$ 66**	**$ 172**	**$ 218**	**$ 81**	**$ 14**	**$ 1,408**	**$ —**	**$ —**
Geological and geophysical	**69**	**6**	**77**	**86**	**107**	**26**	**371**	**—**	**—**
Rentals and other	**218**	**56**	**121**	**109**	**71**	**68**	**643**	**—**	**—**
Total exploration	**1,144**	**128**	**370**	**413**	**259**	**108**	**2,422**	**—**	**—**
Property acquisitions[2]									
Proved	**23**	**21**	**—**	**54**	**—**	**—**	**98**	**—**	**—**
Unproved	**554**	**3**	**30**	**—**	**—**	**—**	**587**	**—**	**—**
Total property acquisitions	**577**	**24**	**30**	**54**	**—**	**—**	**685**	**—**	**—**
Development[3]	**6,275**	**2,048**	**3,701**	**3,924**	**6,715**	**995**	**23,658**	**1,641**	**225**
Total Costs Incurred[4]	**$ 7,996**	**$ 2,200**	**$ 4,101**	**$ 4,391**	**$ 6,974**	**$ 1,103**	**$ 26,765**	**$ 1,641**	**$ 225**
Year Ended December 31, 2014									
Exploration									
Wells	$ 965	$ 87	$ 436	$ 381	$ 207	$ 101	$ 2,177	$ —	$ —
Geological and geophysical	107	72	32	64	88	41	404	—	—
Rentals and other	150	37	198	98	101	103	687	—	—
Total exploration	1,222	196	666	543	396	245	3,268	—	—
Property acquisitions[2]									
Proved	33	1	521	60	—	—	615	—	—
Unproved	196	2	39	—	—	—	237	—	—
Total property acquisitions	229	3	560	60	—	—	852	—	—
Development[3]	8,207	3,226	3,771	4,363	7,182	887	27,636	1,598	393
Total Costs Incurred[4]	$ 9,658	$ 3,425	$ 4,997	$ 4,966	$ 7,578	$ 1,132	$ 31,756	$ 1,598	$ 393
Year Ended December 31, 2013									
Exploration									
Wells	$ 594	$ 495	$ 88	$ 405	$ 262	$ 123	$ 1,967	$ —	$ —
Geological and geophysical	134	70	105	116	29	55	509	—	—
Rentals and other	166	62	147	80	124	131	710	—	—
Total exploration	894	627	340	601	415	309	3,186	—	—
Property acquisitions[2]									
Proved	71	—	26	64	—	1	162	—	—
Unproved	331	2,068	—	203	105	3	2,710	—	—
Total property acquisitions	402	2,068	26	267	105	4	2,872	—	—
Development[3]	7,457	2,306	3,549	4,907	6,611	1,046	25,876	1,027	544
Total Costs Incurred[4]	$ 8,753	$ 5,001	$ 3,915	$ 5,775	$ 7,131	$ 1,359	$ 31,934	$ 1,027	$ 544

1 Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 25, "Asset Retirement Obligations," on page 67.

2 Does not include properties acquired in nonmonetary transactions.

3 Includes $325, $349 and $661 costs incurred prior to assignment of proved reserves for consolidated companies in 2015, 2014, and 2013, respectively.

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

	2015	2014	2013	
Total cost incurred	$ 28.6	$ 33.7	$ 33.5	
Non-oil and gas activities	3.5	4.6	5.8	(Primarily includes LNG, gas-to-liquids and transportation activities)
ARO	(1.0)	(1.2)	(1.4)	
Upstream C&E	$ 31.1	$ 37.1	$ 37.9	Reference page 21 Upstream total

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 15, beginning on page 48, 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, 2015									
Unproved properties	**$ 9,880**	**$ 3,216**	**$ 271**	**$ 1,487**	**$ 1,990**	**$ 23**	**$ 16,867**	**$ 108**	**$ —**
Proved properties and related producing assets	**79,891**	**16,810**	**36,563**	**51,509**	**3,012**	**9,664**	**197,449**	**7,803**	**3,857**
Support equipment	**1,970**	**363**	**1,229**	**1,967**	**1,195**	**176**	**6,900**	**1,452**	**—**
Deferred exploratory wells	**438**	**237**	**443**	**612**	**1,321**	**261**	**3,312**	**—**	**—**
Other uncompleted projects	**7,700**	**5,566**	**6,517**	**5,070**	**29,843**	**2,332**	**57,028**	**3,732**	**425**
Gross Capitalized Costs	**99,879**	**26,192**	**45,023**	**60,645**	**37,361**	**12,456**	**281,556**	**13,095**	**4,282**
Unproved properties valuation	**1,667**	**873**	**209**	**438**	**107**	**23**	**3,317**	**51**	**—**
Proved producing properties – Depreciation and depletion	**53,718**	**8,950**	**21,904**	**35,004**	**1,950**	**8,074**	**129,600**	**3,714**	**984**
Support equipment depreciation	**800**	**208**	**740**	**1,420**	**480**	**161**	**3,809**	**661**	**—**
Accumulated provisions	**56,185**	**10,031**	**22,853**	**36,862**	**2,537**	**8,258**	**136,726**	**4,426**	**984**
Net Capitalized Costs	**$ 43,694**	**$ 16,161**	**$ 22,170**	**$ 23,783**	**$ 34,824**	**$ 4,198**	**$ 144,830**	**$ 8,669**	**$ 3,298**
At December 31, 2014									
Unproved properties	$ 10,095	$ 3,207	$ 286	$ 1,933	$ 1,990	$ 33	$ 17,544	$ 108	$ —
Proved properties and related producing assets	75,511	14,697	33,117	47,007	3,303	9,172	182,807	7,370	3,713
Support equipment	1,670	361	1,193	1,791	796	186	5,997	1,331	—
Deferred exploratory wells	1,012	220	647	734	1,330	252	4,195	—	—
Other uncompleted projects	7,714	5,566	6,691	5,997	23,487	1,841	51,296	2,679	458
Gross Capitalized Costs	96,002	24,051	41,934	57,462	30,906	11,484	261,839	11,488	4,171
Unproved properties valuation	1,332	796	213	634	46	33	3,054	48	—
Proved producing properties – Depreciation and depletion	48,315	6,516	19,729	31,207	2,259	7,540	115,566	3,295	845
Support equipment depreciation	711	203	694	1,276	202	159	3,245	611	—
Accumulated provisions	50,358	7,515	20,636	33,117	2,507	7,732	121,865	3,954	845
Net Capitalized Costs	$ 45,644	$ 16,536	$ 21,298	$ 24,345	$ 28,399	$ 3,752	$ 139,974	$ 7,534	$ 3,326
At December 31, 2013									
Unproved properties	$ 10,228	$ 3,697	$ 267	$ 2,064	$ 1,990	$ 36	$ 18,282	$ 109	$ 29
Proved properties and related producing assets	67,837	12,868	32,936	42,780	3,274	9,592	169,287	6,977	3,408
Support equipment	1,314	344	1,180	1,678	1,608	177	6,301	1,166	—
Deferred exploratory wells	670	297	536	335	1,134	273	3,245	—	—
Other uncompleted projects	9,149	4,175	4,424	5,998	16,000	1,390	41,136	1,638	404
Gross Capitalized Costs	89,198	21,381	39,343	52,855	24,006	11,468	238,251	9,890	3,841
Unproved properties valuation	1,243	707	203	389	6	31	2,579	45	10
Proved producing properties – Depreciation and depletion	45,756	5,695	18,051	27,356	2,083	7,825	106,766	2,672	696
Support equipment depreciation	656	189	647	1,177	384	149	3,202	538	—
Accumulated provisions	47,655	6,591	18,901	28,922	2,473	8,005	112,547	3,255	706
Net Capitalized Costs	$ 41,543	$ 14,790	$ 20,442	$ 23,933	$ 21,533	$ 3,463	$ 125,704	$ 6,635	$ 3,135

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 2015, 2014 and 2013 are shown in the following table. Net income from exploration and production activities as reported on page 46 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 46.

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2015									
Revenues from net production									
Sales	**$ 1,475**	**$ 1,155**	**$ 279**	**$ 6,254**	**$ 889**	**$ 403**	**$ 10,455**	**$ 4,097**	**$ 729**
Transfers	**7,195**	**1,089**	**6,182**	**3,779**	**408**	**829**	**19,482**	**—**	**—**
Total	**8,670**	**2,244**	**6,461**	**10,033**	**1,297**	**1,232**	**29,937**	**4,097**	**729**
Production expenses excluding taxes	**(4,293)**	**(1,162)**	**(1,758)**	**(3,601)**	**(162)**	**(505)**	**(11,481)**	**(510)**	**(365)**
Taxes other than on income	**(430)**	**(123)**	**(124)**	**(15)**	**(172)**	**(2)**	**(866)**	**(279)**	**(31)**
Proved producing properties:									
Depreciation and depletion	**(7,640)**	**(2,519)**	**(2,506)**	**(3,887)**	**(217)**	**(556)**	**(17,325)**	**(501)**	**(169)**
Accretion expense[2]	**(265)**	**(23)**	**(127)**	**(158)**	**(37)**	**(69)**	**(679)**	**(3)**	**(14)**
Exploration expenses	**(1,614)**	**(137)**	**(667)**	**(492)**	**(289)**	**(106)**	**(3,305)**	**—**	**(1)**
Unproved properties valuation	**(583)**	**(55)**	**(24)**	**(79)**	**(61)**	**—**	**(802)**	**—**	**—**
Other income (expense)[3]	**220**	**(291)**	**638**	**21**	**73**	**237**	**898**	**(25)**	**373**
Results before income taxes	**(5,935)**	**(2,066)**	**1,893**	**1,822**	**432**	**231**	**(3,623)**	**2,779**	**522**
Income tax expense	**2,133**	**550**	**(986)**	**(679)**	**(178)**	**(62)**	**778**	**(835)**	**(291)**
Results of Producing Operations	**$ (3,802)**	**$ (1,516)**	**$ 907**	**$ 1,143**	**$ 254**	**$ 169**	**$ (2,845)**	**$ 1,944**	**$ 231**
Year Ended December 31, 2014									
Revenues from net production									
Sales	$ 2,660	$ 1,338	$ 707	$ 8,290	$ 1,466	$ 1,037	$ 15,498	$ 7,717	$ 1,733
Transfers	13,023	2,285	12,546	8,153	888	1,277	38,172	—	—
Total	15,683	3,623	13,253	16,443	2,354	2,314	53,670	7,717	1,733
Production expenses excluding taxes	(4,786)	(1,328)	(2,084)	(4,527)	(191)	(773)	(13,689)	(493)	(670)
Taxes other than on income	(654)	(122)	(140)	(82)	(329)	(4)	(1,331)	(344)	(418)
Proved producing properties:									
Depreciation and depletion	(4,605)	(793)	(3,092)	(3,977)	(208)	(351)	(13,026)	(567)	(175)
Accretion expense[2]	(334)	(22)	(130)	(142)	(32)	(84)	(744)	(9)	(4)
Exploration expenses	(581)	(119)	(383)	(309)	(269)	(281)	(1,942)	—	(5)
Unproved properties valuation	(140)	(219)	(12)	(289)	(40)	(3)	(703)	—	(38)
Other income (expense)[3]	654	674	221	115	102	358	2,124	(28)	(85)
Results before income taxes	5,237	1,694	7,633	7,232	1,387	1,176	24,359	6,276	338
Income tax expense	(1,955)	(471)	(4,924)	(3,604)	(392)	(579)	(11,925)	(1,883)	(284)
Results of Producing Operations	$ 3,282	$ 1,223	$ 2,709	$ 3,628	$ 995	$ 597	$ 12,434	$ 4,393	$ 54

[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 25, "Asset Retirement Obligations," on page 67.

[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

Millions of dollars	Consolidated Companies U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	Affiliated Companies TCO	Other
Year Ended December 31, 2013									
Revenues from net production									
Sales	$ 2,303	$ 1,351	$ 702	$ 9,220	$ 1,431	$ 1,345	$ 16,352	$ 8,522	$ 2,100
Transfers	14,471	1,973	14,804	9,521	984	1,701	43,454	—	—
Total	16,774	3,324	15,506	18,741	2,415	3,046	59,806	8,522	2,100
Production expenses excluding taxes	(4,606)	(1,218)	(2,099)	(4,429)	(193)	(759)	(13,304)	(401)	(444)
Taxes other than on income	(648)	(90)	(149)	(140)	(378)	(3)	(1,408)	(439)	(704)
Proved producing properties:									
Depreciation and depletion	(4,039)	(440)	(2,747)	(3,602)	(342)	(416)	(11,586)	(518)	(179)
Accretion expense[2]	(223)	(22)	(125)	(114)	(28)	(79)	(591)	(9)	(14)
Exploration expenses	(555)	(372)	(203)	(272)	(161)	(258)	(1,821)	—	—
Unproved properties valuation	(129)	(84)	(13)	(141)	(4)	(5)	(376)	—	(10)
Other income (expense)[3]	242	(5)	145	(275)	89	13	209	(81)	462
Results before income taxes	6,816	1,093	10,315	9,768	1,398	1,539	30,929	7,074	1,211
Income tax expense	(2,471)	(289)	(6,545)	(4,824)	(411)	(1,058)	(15,598)	(2,122)	(624)
Results of Producing Operations	$ 4,345	$ 804	$ 3,770	$ 4,944	$ 987	$ 481	$ 15,331	$ 4,952	$ 587

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 25, "Asset Retirement Obligations," on page 67.
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 U.S.	Other Americas[3]	Africa	Asia	Australia/ Oceania	Europe	Total	Affiliated Companies TCO	Other
Year Ended December 31, 2015									
Average sales prices									
Liquids, per barrel	**$ 42.70**	**$ 49.66**	**$ 49.88**	**$ 46.19**	**$ 49.96**	**$ 48.53**	**$ 46.26**	**$ 38.71**	**$ 34.92**
Natural gas, per thousand cubic feet	**1.89**	**3.24**	**1.84**	**4.94**	**6.17**	**5.28**	**3.96**	**1.57**	**2.51**
Average production costs, per barrel[2]	**16.60**	**20.45**	**12.23**	**13.55**	**5.03**	**17.14**	**14.60**	**4.32**	**17.44**
Year Ended December 31, 2014									
Average sales prices									
Liquids, per barrel	$ 84.13	$ 86.23	$ 96.43	$ 89.44	$ 95.17	$ 95.05	$ 89.44	$ 81.07	$ 76.07
Natural gas, per thousand cubic feet	3.90	3.25	1.53	5.86	10.42	9.29	5.44	1.53	6.38
Average production costs, per barrel[2]	20.09	22.77	13.77	17.21	5.53	27.14	17.69	4.47	29.30
Year Ended December 31, 2013									
Average sales prices									
Liquids, per barrel	$ 93.46	$ 91.44	$ 107.22	$ 98.37	$ 103.28	$ 105.78	$ 99.05	$ 88.06	$ 78.87
Natural gas, per thousand cubic feet	3.38	3.03	1.76	6.02	10.61	11.04	5.45	1.50	4.00
Average production costs, per barrel[2]	19.57	21.29	13.93	16.49	5.90	22.87	17.10	4.37	22.69

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.
3 2013 and 2014 conformed to 2015 presentation.

Table V Reserve Quantity Information

Summary of Net Oil and Gas Reserves

Liquids in Millions of Barrels *Natural Gas in Billions of Cubic Feet*	**2015** Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	2014 Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	2013 Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas
Proved Developed									
Consolidated Companies									
U.S.	**933**	**—**	**2,683**	955	—	2,743	976	—	2,632
Other Americas	**109**	**594**	**597**	103	531	739	109	403	943
Africa	**702**	**—**	**1,100**	701	—	1,112	763	—	1,161
Asia	**660**	**—**	**4,933**	584	—	4,607	601	—	4,620
Australia/Oceania	**60**	**—**	**4,330**	38	—	1,117	44	—	1,251
Europe	**76**	**—**	**166**	87	—	167	94	—	200
Total Consolidated	**2,540**	**594**	**13,809**	2,468	531	10,485	2,587	403	10,807
Affiliated Companies									
TCO	**1,020**	**—**	**1,504**	961	—	1,431	884	—	1,188
Other	**91**	**58**	**288**	100	51	317	105	44	330
Total Consolidated and Affiliated Companies	**3,651**	**652**	**15,601**	3,529	582	12,233	3,576	447	12,325
Proved Undeveloped									
Consolidated Companies									
U.S.	**453**	**—**	**1,559**	477	—	1,431	354	—	1,358
Other Americas	**127**	**3**	**117**	135	3	384	134	134	357
Africa	**255**	**—**	**1,837**	320	—	1,856	341	—	1,884
Asia	**130**	**—**	**1,023**	168	—	1,659	191	—	2,125
Australia/Oceania	**93**	**—**	**7,543**	104	—	9,824	87	—	9,076
Europe	**67**	**—**	**58**	79	—	68	72	—	63
Total Consolidated	**1,125**	**3**	**12,137**	1,283	3	15,222	1,179	134	14,863
Affiliated Companies									
TCO	**656**	**—**	**764**	654	—	746	784	—	1,102
Other	**40**	**135**	**935**	45	153	915	49	176	856
Total Consolidated and Affiliated Companies	**1,821**	**138**	**13,836**	1,982	156	16,883	2,012	310	16,821
Total Proved Reserves	**5,472**	**790**	**29,437**	5,511	738	29,116	5,588	757	29,146

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

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

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

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

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the Manager of Corporate Reserves, a corporate department that is separate from the Upstream operating organization. The Manager of Corporate Reserves has more than 30 years' experience working in the oil and gas industry and a Master of Science in Petroleum Engineering degree from Stanford University. His experience includes more than 15 years of managing oil and gas reserves processes. He was chairman of the Society of Petroleum Engineers Oil and Gas Reserves Committee, served on the United Nations Expert Group on Resources Classification, and is a past member of the Joint Committee on Reserves Evaluator Training and the California Conservation Committee. He is an active member of the Society of Petroleum Evaluation Engineers and serves on the Society of Petroleum Engineers Oil and Gas Reserves Committee.

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 *Corporate Reserves Manual,* which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

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

RAC subteams also conduct in-depth reviews during the year of many of the fields that have large proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their compliance with the *Corporate Reserves Manual.*

Technologies Used in Establishing Proved Reserves Additions In 2015, 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 2015, proved undeveloped reserves totaled 4.3 billion barrels of oil-equivalent (BOE), a decrease of 687 million BOE from year-end 2014. The decrease was due to the transfer of 1,027 million BOE to proved developed and 2 million BOE in sales, partially offset by increases of 273 million BOE in extensions and discoveries, 65 million BOE in revisions, and 4 million BOE in improved recovery.

During 2015, investments totaling approximately $14.3 billion in oil and gas producing activities and about $2.3 billion in non-oil and gas producing activities were expended to advance the development of proved undeveloped reserves. Australia accounted for about $6.4 billion of the total, mainly for development and construction activities at the Gorgon and Wheatstone LNG projects. Expenditures of about $2.7 billion in the United States related primarily to various development activities in the Gulf of Mexico and the midcontinent region. In Asia, expenditures during the year totaled approximately $3.2 billion, primarily related to development projects of the TCO affiliate in Kazakhstan, and in Thailand. In Africa, about $2.8 billion was expended on various offshore development and natural gas projects in Nigeria, Angola and Republic of the Congo. Development activities in Canada were primarily responsible for about $1.5 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 2015, the company held approximately 2.2 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 500 million BOE have remained undeveloped for five years or more related to the Gorgon Project. The company is currently constructing liquefaction and other facilities in Australia to develop this natural gas. In Africa, approximately 400 million BOE have remained undeveloped for five years or more, primarily due to facility constraints at various fields and infrastructure associated with the Escravos gas projects in Nigeria. Affiliates account for about 1.1 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more, with the majority related to the TCO affiliate in Kazakhstan. At TCO, further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion.

Annually, the company assesses whether any changes have occurred in facts or circumstances, such as changes to development plans, regulations or government policies, that would warrant a revision to reserve estimates. In 2015, significant reductions in commodity prices negatively impacted the economic limits of oil and gas properties, resulting in proved reserve decreases, and positively 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 2015, 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 38 percent and 46 percent. The consistent completion of major capital projects has kept the ratio in a narrow range over this time period.

Proved Reserve Quantities For the three years ending December 31, 2015, 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, 2015, proved reserves for the company were 11.2 billion BOE. The company's estimated net proved reserves of liquids including crude oil, condensate, natural gas liquids and synthetic oil for the years 2013, 2014 and 2015 are shown in the table on page 77. The company's estimated net proved reserves of natural gas are shown on page 78.

Noteworthy changes in liquids proved reserves for 2013 through 2015 are discussed below and shown in the table on the following page:

Revisions In 2013, improved field performance from various Nigeria and Angola producing assets was primarily responsible for the 94 million barrel increase in Africa. In Asia, drilling performance across numerous assets resulted in an 84 million barrel increase. Improved field performance and drilling associated with Gulf of Mexico projects and drilling in the Midland and Delaware basins accounted for the majority of the 55 million barrel increase in the United States. Synthetic oil reserves in Canada increased by 40 million barrels, primarily due to improved field performance.

In 2014, drilling in the Midland and Delaware basins and improved field performance and drilling in California accounted for the majority of the 90 million barrel increase in the United States. Improved field performance at various Nigeria fields was primarily responsible for the 74 million barrel increase in Africa. In Asia, drilling performance across numerous assets, primarily in Indonesia, resulted in the 80 million barrel increase.

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

Improved Recovery In 2013, improved recovery increased reserves by 57 million barrels due to numerous small projects, including expansions of existing projects in the United States, Europe, Asia, and Africa.

In 2014, improved recovery increased reserves by 34 million barrels, primarily due to secondary recovery projects in the United States, mostly related to steamflood expansions in California.

Extensions and Discoveries In 2013, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 55 million barrel increase in the United States.

In 2014, extensions and discoveries in the Midland and Delaware basins and the Gulf of Mexico were primarily responsible for the 164 million barrel increase in the United States.

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

Purchases In 2014, the purchase of additional reserves in Canada was responsible for the 26 million barrel increase in synthetic oil.

Sales In 2014, the sale of the company's interests in Chad was responsible for the 20 million barrel decrease in Africa.

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, 2013	1,359	223	1,130	837	134	157	513	4,353	1,732	232	164	6,481
Changes attributable to:												
Revisions	55	25	94	84	7	17	40	322	32	(3)	3	354
Improved recovery	26	—	10	10	—	11	—	57	—	—	—	57
Extensions and discoveries	55	4	13	2	—	4	—	78	—	—	—	78
Purchases	2	9	—	—	—	—	—	11	—	—	—	11
Sales	(3)	—	(1)	—	—	—	—	(4)	—	—	—	(4)
Production	(164)	(18)	(142)	(141)	(10)	(23)	(16)	(514)	(96)	(9)	(13)	(632)
Reserves at December 31, 2013[4]	1,330	243	1,104	792	131	166	537	4,303	1,668	220	154	6,345
Changes attributable to:												
Revisions	90	—	74	80	19	9	(32)	240	41	(4)	—	277
Improved recovery	19	1	1	8	—	5	—	34	—	—	—	34
Extensions and discoveries	164	18	2	7	—	8	19	218	—	—	1	219
Purchases	1	—	—	—	—	—	26	27	—	—	—	27
Sales	(6)	—	(20)	—	—	(3)	—	(29)	—	—	—	(29)
Production	(166)	(24)	(140)	(135)	(8)	(19)	(16)	(508)	(94)	(12)	(10)	(624)
Reserves at December 31, 2014[4]	1,432	238	1,021	752	142	166	534	4,285	1,615	204	145	6,249
Changes attributable to:												
Revisions	**(1)**	**(9)**	**60**	**164**	**14**	**(3)**	**80**	**305**	**163**	**—**	**(4)**	**464**
Improved recovery	**7**	**—**	**11**	**2**	**—**	**—**	**—**	**20**	**—**	**—**	**—**	**20**
Extensions and discoveries	**137**	**28**	**4**	**5**	**5**	**—**	**—**	**179**	**—**	**—**	**—**	**179**
Purchases	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Sales	**(6)**	**—**	**(7)**	**—**	**—**	**—**	**—**	**(13)**	**—**	**—**		**(13)**
Production	**(183)**	**(21)**	**(132)**	**(133)**	**(8)**	**(20)**	**(17)**	**(514)**	**(102)**	**(11)**	**(10)**	**(637)**
Reserves at December 31, 2015[4]	**1,386**	**236**	**957**	**790**	**153**	**143**	**597**	**4,262**	**1,676**	**193**	**131**	**6,262**

1 Ending reserve balances in North America were 155, 142 and 141 and in South America were 81, 96 and 102 in 2015, 2014 and 2013, respectively.
2 Reserves associated with Canada.
3 Ending reserve balances in Africa were 34, 37 and 37 and in South America were 97, 108 and 117 in 2015, 2014 and 2013, respectively.
4 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 8 for the definition of a PSC). PSC-related reserve quantities are 20 percent, 19 percent and 20 percent for consolidated companies for 2015, 2014 and 2013, 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, 2013	3,722	1,475	3,081	6,867	10,252	257	25,654	2,299	1,242	29,195
Changes attributable to:										
Revisions	(234)	(59)	27	627	229	46	636	117	(35)	718
Improved recovery	3	—	2	6	—	4	15	—	—	15
Extensions and discoveries	951	—	27	16	—	27	1,021	—	—	1,021
Purchases	12	32	—	60	—	—	104	—	—	104
Sales	(10)	—	(1)	—	—	(1)	(12)	—	—	(12)
Production[3]	(454)	(148)	(91)	(831)	(154)	(70)	(1,748)	(126)	(21)	(1,895)
Reserves at December 31, 2013	3,990	1,300	3,045	6,745	10,327	263	25,670	2,290	1,186	29,146
Changes attributable to:										
Revisions	76	(110)	35	252	775	36	1,064	9	34	1,107
Improved recovery	2	1	1	—	—	1	5	—	—	5
Extensions and discoveries	614	56	—	79	—	3	752	—	32	784
Purchases	1	—	—	21	—	—	22	—	—	22
Sales	(53)	(1)	(3)	—	—	(5)	(62)	—	—	(62)
Production[3]	(456)	(123)	(110)	(831)	(161)	(63)	(1,744)	(122)	(20)	(1,886)
Reserves at December 31, 2014	4,174	1,123	2,968	6,266	10,941	235	25,707	2,177	1,232	29,116
Changes attributable to:										
Revisions	**(66)**	**(435)**	**27**	**480**	**974**	**49**	**1,029**	**218**	**2**	**1,249**
Improved recovery	**1**	**—**	**—**	**—**	**—**	**—**	**1**	**—**	**—**	**1**
Extensions and discoveries	**659**	**147**	**61**	**61**	**118**	**—**	**1,046**	**—**	**—**	**1,046**
Purchases	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Sales	**(48)**	**—**	**(5)**	**—**	**—**	**—**	**(53)**	**—**	**—**	**(53)**
Production[3]	**(478)**	**(121)**	**(114)**	**(851)**	**(160)**	**(60)**	**(1,784)**	**(127)**	**(11)**	**(1,922)**
Reserves at December 31, 2015	**4,242**	**714**	**2,937**	**5,956**	**11,873**	**224**	**25,946**	**2,268**	**1,223**	**29,437**

[1] Ending reserve balances in North America and South America were 174, 59, 54 and 540, 1,064, 1,246 in 2015, 2014 and 2013, respectively.
[2] Ending reserve balances in Africa and South America were 1,044, 1,043, 1,009 and 179, 189, 177 in 2015, 2014 and 2013, respectively.
[3] Total "as sold" volumes are 1,742 BCF, 1,695 BCF and 1,702 BCF for 2015, 2014 and 2013, respectively; 2013 conformed to 2014 presentation.
[4] Includes reserve quantities related to production-sharing contracts (PSC) (refer to page 8 for the definition of a PSC). PSC-related reserve quantities are 16 percent, 19 percent and 20 percent for consolidated companies for 2015, 2014 and 2013, respectively.

Noteworthy changes in natural gas proved reserves for 2013 through 2015 are discussed below and shown in the table above:

Revisions In 2013, net revisions of 627 BCF in Asia were primarily due to development drilling and improved field performance in Bangladesh and Thailand. In Australia, drilling performance drove the 229 BCF increase. The majority of the net decrease of 234 BCF in the United States was due to a change in development plans in the Appalachian region.

In 2014, net revisions of 775 BCF in Australia were primarily due to development drilling at Gorgon.

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

Extensions and Discoveries In 2013, extensions and discoveries of 951 BCF in the United States were primarily in the Appalachian region.

In 2014, extensions and discoveries of 614 BCF in the United States were primarily in the Appalachian region and the Delaware Basin.

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

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, 2015										
Future cash inflows from production	**$ 67,536**	**$ 39,363**	**$ 52,128**	**$ 58,645**	**$ 93,550**	**$ 8,561**	**$ 319,783**	**$ 75,378**	**$ 17,519**	**$ 412,680**
Future production costs	**(33,895)**	**(26,477)**	**(22,963)**	**(27,499)**	**(10,814)**	**(6,994)**	**(128,642)**	**(17,959)**	**(6,546)**	**(153,147)**
Future development costs	**(12,625)**	**(5,485)**	**(6,562)**	**(8,924)**	**(11,612)**	**(1,751)**	**(46,959)**	**(17,232)**	**(3,226)**	**(67,417)**
Future income taxes	**(4,161)**	**(2,316)**	**(14,681)**	**(9,229)**	**(21,337)**	**70**	**(51,654)**	**(12,056)**	**(3,460)**	**(67,170)**
Undiscounted future net cash flows	**16,855**	**5,085**	**7,922**	**12,993**	**49,787**	**(114)**	**92,528**	**28,131**	**4,287**	**124,946**
10 percent midyear annual discount for timing of estimated cash flows	**(5,871)**	**(2,830)**	**(2,230)**	**(3,673)**	**(26,179)**	**292**	**(40,491)**	**(15,249)**	**(2,239)**	**(57,979)**
Standardized Measure Net Cash Flows	**$ 10,984**	**$ 2,255**	**$ 5,692**	**$ 9,320**	**$ 23,608**	**$ 178**	**$ 52,037**	**$ 12,882**	**$ 2,048**	**$ 66,967**
At December 31, 2014										
Future cash inflows from production	$ 138,385	$ 67,102	$ 103,304	$ 99,741	$ 142,541	$ 18,168	$ 569,241	$ 144,721	$ 37,511	$ 751,473
Future production costs	(42,817)	(30,899)	(26,992)	(34,359)	(12,744)	(10,814)	(158,625)	(30,015)	(17,061)	(205,701)
Future development costs	(13,616)	(8,283)	(9,486)	(12,629)	(15,681)	(3,031)	(62,726)	(19,349)	(4,454)	(86,529)
Future income taxes	(27,129)	(8,445)	(47,884)	(24,225)	(34,235)	(2,692)	(144,610)	(28,607)	(6,634)	(179,851)
Undiscounted future net cash flows	54,823	19,475	18,942	28,528	79,881	1,631	203,280	66,750	9,362	279,392
10 percent midyear annual discount for timing of estimated cash flows	(23,257)	(12,082)	(6,145)	(8,570)	(43,325)	(380)	(93,759)	(34,987)	(5,294)	(134,040)
Standardized Measure Net Cash Flows	$ 31,566	$ 7,393	$ 12,797	$ 19,958	$ 36,556	$ 1,251	$ 109,521	$ 31,763	$ 4,068	$ 145,352
At December 31, 2013[1]										
Future cash inflows from production	$ 136,942	$ 73,468	$ 117,119	$ 111,970	$ 130,620	$ 20,232	$ 590,351	$ 157,108	$ 43,380	$ 790,839
Future production costs	(39,009)	(29,373)	(27,800)	(35,716)	(12,593)	(10,099)	(154,590)	(32,245)	(18,027)	(204,862)
Future development costs	(12,058)	(10,149)	(10,983)	(17,290)	(18,220)	(2,644)	(71,344)	(12,852)	(3,879)	(88,075)
Future income taxes	(28,458)	(9,454)	(53,953)	(26,162)	(29,942)	(4,727)	(152,696)	(33,603)	(9,418)	(195,717)
Undiscounted future net cash flows	57,417	24,492	24,383	32,802	69,865	2,762	211,721	78,408	12,056	302,185
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(15,217)	(8,165)	(10,901)	(39,117)	(888)	(97,343)	(41,444)	(6,482)	(145,269)
Standardized Measure Net Cash Flows	$ 34,362	$ 9,275	$ 16,218	$ 21,901	$ 30,748	$ 1,874	$ 114,378	$ 36,964	$ 5,574	$ 156,916

[1] 2013 conformed to 2014 and 2015 presentation.

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

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

Millions of dollars	Consolidated Companies[1]	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2013	$ 110,626	$ 45,214	$ 155,840
Sales and transfers of oil and gas produced net of production costs	(43,760)	(8,692)	(52,452)
Development costs incurred	22,907	1,411	24,318
Purchases of reserves	184	—	184
Sales of reserves	243	—	243
Extensions, discoveries and improved recovery less related costs	3,135	—	3,135
Revisions of previous quantity estimates	22,796	1,306	24,102
Net changes in prices, development and production costs	(22,591)	(5,925)	(28,516)
Accretion of discount	18,510	6,406	24,916
Net change in income tax	2,328	2,818	5,146
Net change for 2013	3,752	(2,676)	1,076
Present Value at December 31, 2013	$ 114,378	$ 42,538	$ 156,916
Sales and transfers of oil and gas produced net of production costs	(38,935)	(7,578)	(46,513)
Development costs incurred	25,687	1,963	27,650
Purchases of reserves	255	—	255
Sales of reserves	(1,178)	—	(1,178)
Extensions, discoveries and improved recovery less related costs	3,956	215	4,171
Revisions of previous quantity estimates	17,462	1,573	19,035
Net changes in prices, development and production costs	(34,953)	(12,496)	(47,449)
Accretion of discount	18,884	5,926	24,810
Net change in income tax	3,965	3,690	7,655
Net change for 2014	(4,857)	(6,707)	(11,564)
Present Value at December 31, 2014	$ 109,521	$ 35,831	$ 145,352
Sales and transfers of oil and gas produced net of production costs	**(17,145)**	**(3,637)**	**(20,782)**
Development costs incurred	**21,703**	**1,863**	**23,566**
Purchases of reserves	**2**	**—**	**2**
Sales of reserves	**(109)**	**—**	**(109)**
Extensions, discoveries and improved recovery less related costs	**1,415**	**—**	**1,415**
Revisions of previous quantity estimates	**9,171**	**3,607**	**12,778**
Net changes in prices, development and production costs	**(143,055)**	**(37,056)**	**(180,111)**
Accretion of discount	**18,179**	**4,965**	**23,144**
Net change in income tax	**52,355**	**9,357**	**61,712**
Net change for 2015	**(57,484)**	**(20,901)**	**(78,385)**
Present Value at December 31, 2015	**$ 52,037**	**$ 14,930**	**$ 66,967**

[1] 2013 conformed to 2014 and 2015 presentation.

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 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 provide a targeted, high-quality core acreage position primarily in the Marcellus Shale.

board of directors

John S. Watson, 59
Chairman of the Board and Chief Executive Officer since 2010. Previously he was elected a Director and Vice Chairman in 2009; Executive Vice President, Strategy and Development; Corporate Vice President and President, Chevron International Exploration and Production Company; Vice President and Chief Financial Officer; and Corporate Vice President, Strategic Planning. He serves on the Board of Directors and the Executive Committee of the American Petroleum Institute. Joined Chevron in 1980.

Alexander B. Cummings Jr., 59
Director since 2014. He is a retired Executive Vice President and Chief Administrative Officer of The Coca-Cola Company, the world's largest beverage manufacturer. Previously he was President and Chief Operating Officer of Coca-Cola's Africa Group. He is a Director of Coca-Cola Bottling Co. Consolidated. (1)

Linnet F. Deily, 70
Director since 2006. She served as a Deputy U.S. Trade Representative and U.S. Ambassador to the World Trade Organization. Previously she was Vice Chairman of Charles Schwab Corporation. She is a Director of Honeywell International Inc. (2, 3)

Robert E. Denham, 70
Director since 2004. He is a Partner in the law firm of Munger, Tolles & Olson LLP. Previously he was Chairman and Chief Executive Officer of Salomon Inc. He is a Director of The New York Times Company; Oaktree Capital Group, LLC; and Fomento Económico Mexicano, S.A. de C.V. (1, 4)

Alice P. Gast, 57
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. (1)

Enrique Hernandez Jr., 60
Director since 2008. He is Chairman, Chief Executive Officer and President of Inter-Con Security Systems, Inc., a global provider of security services to local, state, federal and foreign governments, utilities, and corporations. He is a Director of McDonald's Corporation; Nordstrom, Inc.; and Wells Fargo & Company. (2, 4)

Jon M. Huntsman Jr., 56
Director since 2014. He served as U.S. Ambassador to China and was Governor of Utah for two consecutive terms. He is Chairman of the Board of the Atlantic Council, a nonprofit that promotes leadership and engagement in international affairs, and Chairman of the Board of the Huntsman Cancer Foundation, a nonprofit that financially supports research, education and patient care initiatives at the Huntsman Cancer Institute at the University of Utah. In 2011 he was a candidate for the Republican nomination for President of the United States. He is a Director of Caterpillar Inc., Ford Motor Company and Hilton Worldwide. (2, 3)

Charles W. Moorman IV, 64
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 served as President at Norfolk Southern from 2004 to 2013. (1)

John G. Stumpf, 62
Director since 2010. He is Chairman of the Board, Chief Executive Officer and President of Wells Fargo & Company, a diversified financial services company. He served as President of Wells Fargo from 2005 to 2015. He is a Director of Target Corporation. (3, 4)

Ronald D. Sugar, 67
Lead Director since 2015 and a **Director** since 2005. He is a retired Chairman of the Board and Chief Executive Officer of Northrop Grumman Corporation. He is a Senior Advisor to various businesses and organizations, including Ares Management LLC, a leading private investment firm; Bain & Company, a global consulting firm; Temasek Americas Advisory Panel, a private investment company based in Singapore; and the G100 Network and the World 50, peer-to-peer exchanges for current and former senior executives from some of the world's largest companies. He is a Director of Amgen Inc., Air Lease Corporation and Apple Inc. (3, 4)

Inge G. Thulin, 62
Director since 2015. He is Chairman of the Board, President and Chief Executive Office of 3M Company, a diversified technology company. Previously he was Executive Vice President and Chief Operating Officer of 3M. Prior to that he was the company's Executive Vice President of International Operations. (3, 4)

Retiring Director

Carl Ware, 72, a Director since 2001, has reached the mandatory retirement age and will not stand for re-election at the Annual Meeting in May. He is a retired Executive Vice President of The Coca-Cola Company. (2, 4)

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

corporate officers

Paul V. Bennett, 62
Vice President and Treasurer since 2011. Responsible for banking, financing, cash management, insurance, pension investments, and credit and receivables activities across the corporation. Previously Vice President, Finance, Downstream and Chemicals. Joined the company in 1980.

Pierre R. Breber, 51
Executive Vice President, Downstream and Chemicals, since January 2016. Responsible for directing the company's worldwide manufacturing, marketing, lubricants, chemicals and Oronite additives businesses, and Chevron's joint-venture Chevron Phillips Chemical Company. Previously Executive Vice President, Gas and Midstream, and Managing Director, Asia South Business Unit. Joined the company in 1989.

Mary A. Francis, 51
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 Deputy Corporate Secretary; Chief Corporate Counsel, Corporation Law Department; General Counsel, Chevron Asia Pacific Exploration and Production Company; Managing Counsel, Chevron Pipe Line Company and Chevron Shipping Company; and Lead Senior Counsel, Chevron Shipping Company. Joined the company in 2002.

Joseph C. Geagea, 56
Executive Vice President, Technology, Projects and Services, since 2015. Responsible for energy technology; delivery of major capital projects; procurement; information technology; health, environment and safety; upstream production services; and talent selection and development in support of Chevron's upstream, downstream and midstream businesses. Previously Senior Vice President, Technology, Projects and Services, and Corporate Vice President and President, Chevron Gas and Midstream. Joined the company in 1982.

James W. Johnson, 57
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.

Joe W. Laymon, 63
Vice President, Human Resources and Corporate Services, since 2008. Responsible for human resources, medical services, security, aviation, diversity, ombuds, and business and real estate services. Previously Group Vice President, Corporate Human Resources and Labor Affairs, Ford Motor Company. Joined the company in 2008.

Wesley E. Lohec, 56
Vice President, Health, Environment and Safety (HES), since 2011. Responsible for HES strategic planning and issues management, compliance assurance, emergency response, and Chevron's Environmental Management Company. Previously Managing Director, Latin America, Chevron Africa and Latin America Exploration and Production Company. Joined the company in 1981.

Charles N. Macfarlane, 61
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 Chevron in 1984 upon the merger with Gulf Oil Corporation.

Joseph M. Naylor, 55
Vice President, Policy, Government and Public Affairs, since April 2016. Responsible for U.S. and international government relations, all aspects of communications, and the company's worldwide efforts to protect and enhance its reputation. Previously Vice President, Strategic Planning. Joined Chevron in 1982.

Mark A. Nelson, 52
Vice President, Strategic Planning, since April 2016. Responsible for advising senior corporate executives in setting strategic direction for the company, allocating capital and other resources, and determining operating unit performance measures and targets. Previously President, International Products. Joined Chevron in 1985.

Jeanette L. Ourada, 50
Vice President and Comptroller since 2015. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, and Finance Shared Services. Previously General Manager, Finance Shared Services. Joined Chevron in 2005 upon the merger with Unocal Corporation.

R. Hewitt Pate, 53
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 Chevron in 2009.

Jay R. Pryor, 58
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 Chevron in 1979.

Michael K. Wirth, 55
Executive Vice President, Midstream and Development, since January 2016. Responsible for supply and trading, gas commercialization, and the company's midstream operating units engaged in transportation and power, as well as corporate strategy and business development. Previously Executive Vice President, Downstream and Chemicals; President, Global Supply and Trading; and President, Marketing, Asia/Middle East/Africa Strategic Business Unit. Joined Chevron in 1982.

Patricia E. Yarrington, 60
Vice President and Chief Financial Officer since 2009. Responsible for comptroller, tax, treasury, audit and investor relations activities. Served as Chairman of the San Francisco Federal Reserve's Board of Directors in 2013 and 2014. Previously Corporate Vice President and Treasurer; Corporate Vice President, Policy, Government and Public Affairs; Corporate Vice President, Strategic Planning; and President, Chevron Canada Limited. Joined Chevron in 1980.

Executive Committee
John S. Watson, Pierre R. Breber, Joseph C. Geagea, James W. Johnson, R. Hewitt Pate, Michael K. Wirth and Patricia E. Yarrington. Mary A. Francis, Secretary.

stockholder and investor information

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

Stockholder information
Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to Chevron's transfer agent and registrar:
Computershare
P.O. Box 30170
College Station, TX 77842-3170
800 368 8357
www.computershare.com/investor

Overnight correspondence should be sent to:
Computershare
211 Quality Circle, Suite 210
College Station, TX 77845-4470

The Computershare Investment Plan features dividend reinvestment, optional cash investments of $50 to $100,000 a year and automatic stock purchase.

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

Annual meeting
The Annual Meeting of stockholders will be held at 8:00 a.m. PDT, Wednesday, May 25, 2016, at:
Chevron Park Auditorium
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

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

Investor information
Securities analysts, portfolio managers and representatives of financial institutions may contact:
Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road, A3064
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" and "us" may refer to one or more of its 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

2015 Annual Report

2015 Supplement to the Annual Report

2015 Corporate Responsibility Report

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 writing to:
Comptroller's Department
Chevron Corporation
6001 Bollinger Canyon Road, A3140
San Ramon, CA 94583-2324

The *2015 Corporate Responsibility Report* is available in May on the company's website, Chevron.com/CR, or a copy may be requested by writing to:
Policy, Government and Public Affairs
Corporate Responsibility Communications
Chevron Corporation
6001 Bollinger Canyon Road
Building G
San Ramon, CA 94583-2324

Additional information about the company's corporate responsibility efforts can be found on Chevron's website at Chevron.com/CR and Chevron.com/CreatingProsperity.

Details of the company's *political contributions* for 2015 are available on the company's website, Chevron.com, or by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road
Building G
San Ramon, CA 94583-2324

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

This *Annual Report* contains forward-looking statements — identified by words such as "expects," "intends," "projects," etc. — 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 9 for a discussion of some of the factors that could cause actual results to differ materially.

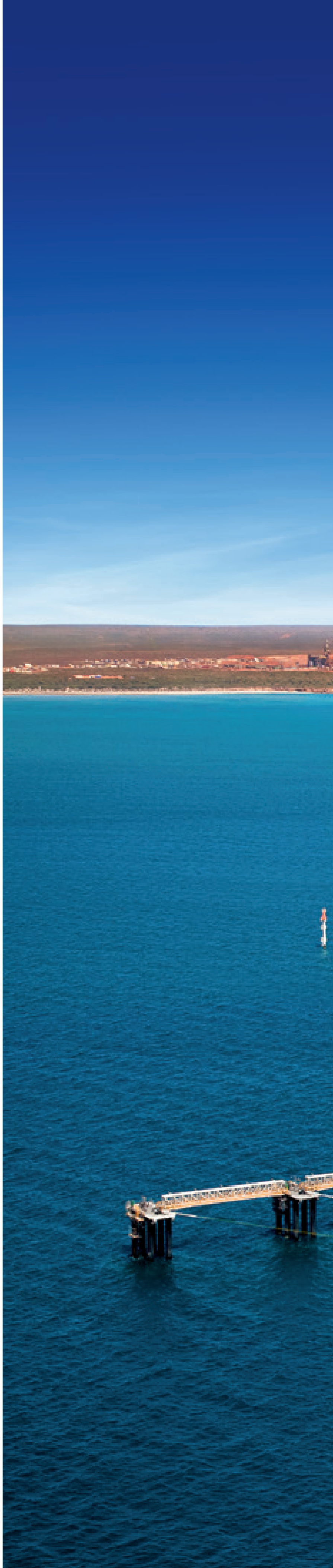
PHOTOGRAPHY
Cover: Darrell Brown; **Page 2:** Eric Myer

PRODUCED BY Policy, Government and Public Affairs and Comptroller's Departments, Chevron Corporation
DESIGN Design One — San Francisco, California
PRINTING ColorGraphics — Los Angeles, California

Hold this QR code to your smartphone and learn more about Chevron.

If you do not have a QR code reader on your phone, go to your app store and search "QR Reader."

Chevron.com/AnnualReport/2015



Chevron Corporation
6001 Bollinger Canyon Road, San Ramon, CA 94583-2324 USA
www.chevron.com

MIX
Paper from responsible sources
FSC® C102835

10% Recycled 100% Recyclable

912-0975

Chevron

2015 supplement to the annual report

human energy®

table of contents

Cover photo: The 37,000-metric-ton Wheatstone topsides were installed onto the steel gravity structure in April 2015, forming the Wheatstone platform.

Inside front cover photo: The Wheatstone platform topsides departed the fabrication yard in March 2015.

2015 at a glance

financial highlights

sales and other operating revenues $129.9 billion

net income attributable to chevron corporation $4.6 billion, $2.45 per share - diluted

return on capital employed 2.5%

cash flow from operations $19.5 billion

cash dividends $4.28 per share

corporate strategies

Financial-return objective – Create shareholder value and achieve sustained financial returns from operations that will enable Chevron to outperform its competitors.

Enterprise strategies – Invest in people to strengthen organizational capability and develop a talented global workforce that gets results the right way. Execute with excellence through rigorous application of the company's operational excellence and capital stewardship systems and disciplined cost management. Grow profitably by using competitive advantages to maximize value from existing assets and capture new opportunities.

Major business strategies – Upstream – grow profitably in core areas and build new legacy positions. Downstream – deliver competitive returns and grow earnings across the value chain. Midstream and Development – apply commercial excellence in supply, trading and transportation to enable success of upstream and downstream strategies. Technology – differentiate performance through technology.

accomplishments

Corporate

Safety – Achieved one of the company's best years in overall operational excellence performance and the best year ever in preventing significant incidents that could have corporate-level impact. The company's days-away-from-work rate and motor-vehicle-crash rate set record lows, and the total-recordable-incident rate and petroleum spill volume matched last year's record lows.

Dividends – Paid $8.0 billion in dividends, with 2015 marking the 28th consecutive year of higher annual dividend payouts.

Capital and exploratory expenditures – Invested $34.0 billion in the company's businesses, including $3.4 billion (Chevron share) of spending by affiliates. Announced 2016 projected outlays of $26.6 billion, including $4.5 billion of affiliate expenditures. Focus is to complete and ramp up projects under construction; fund high-return, short-cycle investments; and preserve options for viable long-cycle projects.

Portfolio management – Realized $5.7 billion in proceeds from asset divestments.

Upstream

Exploration – Achieved an exploration drilling success rate of 62 percent with 36 discoveries worldwide, and added 1.8 billion barrels of oil-equivalent resources. Continued shale and tight resource drilling programs in Argentina, Canada and the United States.

Portfolio additions – Acquired offshore acreage in Canada, Mauritania, Myanmar, New Zealand and the U.S. Gulf of Mexico. Added unconventional acreage in the Marcellus/Utica trend in the United States.

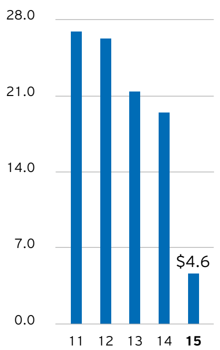
Production – Produced 2.622 million net oil-equivalent barrels per day, with about 73 percent of the volume outside the United States, in more than 20 countries.

Major projects – Continued progress on the company's development projects to deliver future production growth. Achieved first production at the Lianzi Project in the Angola–Republic of Congo Joint Development Area, the Moho Nord Project in Republic of Congo and the Agbami 3 Project in Nigeria. Continued to ramp up production at the Jack/St. Malo Project in the U.S. Gulf of Mexico and in the Permian Basin in Texas and New Mexico. Progressed the construction of the Gorgon and Wheatstone projects in Australia.

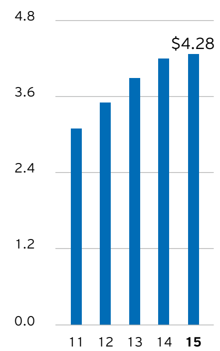
Downstream

Chemical – Advanced construction of a petrochemicals project in Texas that includes an ethane cracker with an annual design capacity of 1.5 million metric tons and two polyethylene units, each with an annual design capacity of 500,000 metric tons (all 50 percent-owned). Began commercial operations of a 100,000-metric-ton-per-year expansion of normal alpha olefins capacity in Texas (50 percent-owned).

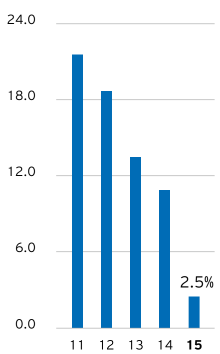
Net Income Attributable to Chevron Corporation
Billions of dollars



Annual Cash Dividends
Dollars per share



Return on Capital Employed
Percent



Financial Summary

Millions of dollars	**2015**	2014	2013	2012	2011
					Year ended December 31
Net income attributable to Chevron Corporation	**$ 4,587**	$ 19,241	$ 21,423	$ 26,179	$ 26,895
Sales and other operating revenues	**129,925**	200,494	220,156	230,590	244,371
Cash dividends – common stock	**7,992**	7,928	7,474	6,844	6,139
Capital and exploratory expenditures	**33,979**	40,316	41,877	34,229	29,066
Cash provided by operating activities	**19,456**	31,475	35,002	38,812	41,098
Total cash and cash equivalents at December 31	**11,022**	12,785	16,245	20,939	15,864
Total assets at December 31	**266,103**	266,026	253,753	232,982	209,474
Total debt and capital lease obligations at December 31	**38,592**	27,818	20,431	12,192	10,152
Total liabilities at December 31	**112,217**	109,835	103,326	95,150	87,293
Chevron Corporation stockholders' equity at December 31	**152,716**	155,028	149,113	136,524	121,382
Share repurchases	**–**	5,000	5,000	5,000	4,250
Market valuation at December 31	**168,103**	209,270	237,258	208,984	209,289

Common Stock

	2015	2014	2013	2012	2011
					Year ended December 31
Number of shares outstanding at December 31 (Millions)	**1,868.6**	1,865.5	1,899.4	1,932.5	1,967.0
Weighted-average shares outstanding for the year (Millions)	**1,867.9**	1,883.6	1,916.3	1,949.7	1,985.7
Per-share data					
Net income attributable to Chevron Corporation					
– Basic	**$ 2.46**	$ 10.21	$ 11.18	$ 13.42	$ 13.54
– Diluted	**2.45**	10.14	11.09	13.32	13.44
Cash dividends	**4.28**	4.21	3.90	3.51	3.09
Chevron Corporation stockholders' equity at December 31	**81.73**	83.10	78.50	70.65	61.71
Market price					
– Close at December 31	**89.96**	112.18	124.91	108.14	106.40
– Intraday high	**113.00**	135.10	127.83	118.53	110.01
– Intraday low	**69.58**	100.15	108.74	95.73	86.68

Financial Ratios*

	2015	2014	2013	2012	2011
					Year ended December 31
Current ratio	**1.3**	1.3	1.5	1.6	1.6
Interest coverage ratio	**9.9**	87.2	126.2	191.3	165.4
Debt ratio	**20.2 %**	15.2 %	12.1 %	8.2 %	7.7 %
Net debt to capital ratio	**14.2 %**	8.0 %	2.3 %	(6.5)%	(7.5)%
Return on stockholders' equity	**3.0 %**	12.7 %	15.0 %	20.3 %	23.8 %
Return on capital employed	**2.5 %**	10.9 %	13.5 %	18.7 %	21.6 %
Return on total assets	**1.7 %**	7.4 %	8.8 %	11.8 %	13.6 %
Cash dividends/net income (payout ratio)	**174.2 %**	41.2 %	34.9 %	26.1 %	22.8 %
Cash dividends/cash from operations	**41.1 %**	25.2 %	21.4 %	17.6 %	14.9 %
Total stockholder return	**(16.0)%**	(6.9)%	19.2 %	5.0 %	20.3 %

* Refer to page 51 for financial ratio definitions.

Capital Employed

Millions of dollars		**2015**	2014	2013	2012	2011
						Year ended December 31
Upstream	– United States	**$ 29,313**	$ 30,984	$ 29,645	$ 27,582	$ 22,950
	– International	**125,418**	113,395	98,063	77,721	65,597
	– Goodwill	**4,588**	4,593	4,639	4,640	4,642
	– Total	**159,319**	148,972	132,347	109,943	93,189
Downstream	– United States	**14,239**	13,835	12,928	11,769	11,077
	– International	**10,805**	11,215	10,325	9,905	10,284
	– Total	**25,044**	25,050	23,253	21,674	21,361
All Other		**8,115**	9,987	15,258	18,407	17,783
Total Capital Employed		**$192,478**	$184,009	$170,858	$150,024	$132,333

Employees

Number of employees	**2015**	2014	2013	2012	2011
					Year ended December 31
Employees excluding service station employees	**58,178**	61,456	61,345	58,286	57,376
Service station employees	**3,316**	3,259	3,205	3,656	3,813
Total Employed	**61,494**	64,715	64,550	61,942	61,189

Consolidated Statement of Income

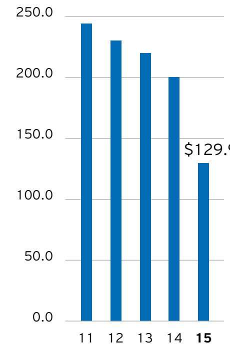
Millions of dollars	2015	2014	2013	2012	2011
					Year ended December 31
Revenues and Other Income					
Total sales and other operating revenues	**$129,925**	$200,494	$220,156	$230,590	$244,371
Income from equity affiliates	**4,684**	7,098	7,527	6,889	7,363
Other Income	**3,868**	4,378	1,165	4,430	1,972
Total Revenues and Other Income	**138,477**	211,970	228,848	241,909	253,706
Costs and Other Deductions					
Purchased crude oil and products	**69,751**	119,671	134,696	140,766	149,923
Operating expenses	**23,034**	25,285	24,627	22,570	21,649
Selling, general and administrative expenses	**4,443**	4,494	4,510	4,724	4,745
Exploration expenses	**3,340**	1,985	1,861	1,728	1,216
Depreciation, depletion and amortization	**21,037**	16,793	14,186	13,413	12,911
Taxes other than on income	**12,030**	12,540	13,063	12,376	15,628
Total Costs and Other Deductions	**133,635**	180,768	192,943	195,577	206,072
Income Before Income Tax Expense	**4,842**	31,202	35,905	46,332	47,634
Income tax expense	**132**	11,892	14,308	19,996	20,626
Net Income	**4,710**	19,310	21,597	26,336	27,008
Less: Net income attributable to noncontrolling interests	**123**	69	174	157	113
Net Income Attributable to Chevron Corporation	**$ 4,587**	$ 19,241	$ 21,423	$ 26,179	$ 26,895

Earnings by Major Operating Area

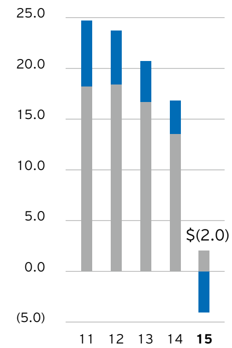
Millions of dollars		2015	2014	2013	2012	2011
						Year ended December 31
Upstream	– United States	**$ (4,055)**	$ 3,327	$ 4,044	$ 5,332	$ 6,512
	– International	**2,094**	13,566	16,765	18,456	18,274
	– Total	**(1,961)**	16,893	20,809	23,788	24,786
Downstream	– United States	**3,182**	2,637	787	2,048	1,506
	– International	**4,419**	1,699	1,450	2,251	2,085
	– Total	**7,601**	4,336	2,237	4,299	3,591
All Other*		**(1,053)**	(1,988)	(1,623)	(1,908)	(1,482)
Net Income Attributable to Chevron Corporation		**$ 4,587**	$ 19,241	$ 21,423	$ 26,179	$ 26,895

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

Total Sales & Other Operating Revenues
Billions of dollars

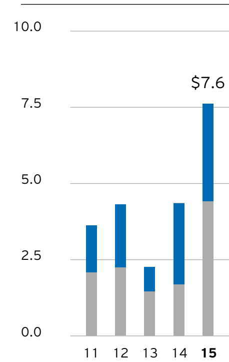


Worldwide Upstream Earnings
Billions of dollars



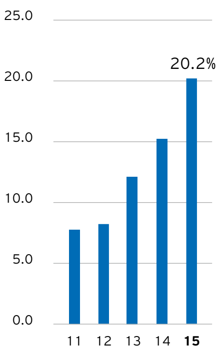
United States
International

Worldwide Downstream Earnings
Billions of dollars

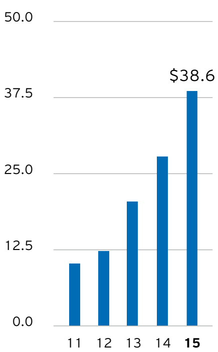


United States
International

Ratio of Total Debt to Total Debt-Plus-Chevron Corporation Stockholders' Equity
Percent



Total Debt at Year-End
Billions of dollars



Consolidated Balance Sheet

Millions of dollars	At December 31 2015	2014	2013	2012	2011
Assets					
Cash and cash equivalents	**$ 11,022**	$ 12,785	$ 16,245	$ 20,939	$ 15,864
Time deposits	**–**	8	8	708	3,958
Marketable securities	**310**	422	263	266	249
Accounts and notes receivable, net	**12,860**	16,736	21,622	20,997	21,793
Inventories:					
Crude oil and petroleum products	**3,535**	3,854	3,879	3,923	3,420
Chemicals	**490**	467	491	475	502
Materials, supplies and other	**2,309**	2,184	2,010	1,746	1,621
Total inventories	**6,334**	6,505	6,380	6,144	5,543
Prepaid expenses and other current assets	**4,821**	5,776	5,732	6,666	5,827
Total Current Assets	**35,347**	42,232	50,250	55,720	53,234
Long-term receivables, net	**2,412**	2,817	2,833	3,053	2,233
Investments and advances	**27,110**	26,912	25,502	23,718	22,868
Properties, plant and equipment, at cost	**340,277**	327,289	296,433	263,481	233,432
Less: Accumulated depreciation, depletion and amortization	**151,881**	144,116	131,604	122,133	110,824
Properties, plant and equipment, net	**188,396**	183,173	164,829	141,348	122,608
Deferred charges and other assets	**6,801**	6,299	5,120	4,503	3,889
Goodwill	**4,588**	4,593	4,639	4,640	4,642
Assets held for sale	**1,449**	–	580	–	–
Total Assets	**$266,103**	$266,026	$253,753	$232,982	$209,474
Liabilities and Equity					
Short-term debt	**$ 4,928**	$ 3,790	$ 374	$ 127	$ 340
Accounts payable	**13,516**	19,000	22,815	22,776	22,147
Accrued liabilities	**4,833**	5,328	5,402	5,738	5,287
Federal and other taxes on income	**2,069**	2,575	3,092	4,341	4,584
Other taxes payable	**1,118**	1,233	1,335	1,230	1,242
Total Current Liabilities	**26,464**	31,926	33,018	34,212	33,600
Long-term debt	**33,584**	23,960	19,960	11,966	9,684
Capital lease obligations	**80**	68	97	99	128
Deferred credits and other noncurrent obligations	**23,465**	23,549	22,982	21,502	19,181
Noncurrent deferred income taxes	**20,689**	21,920	21,301	17,672	15,544
Noncurrent employee benefit plans	**7,935**	8,412	5,968	9,699	9,156
Total Liabilities	**112,217**	109,835	103,326	95,150	87,293
Common stock	**1,832**	1,832	1,832	1,832	1,832
Capital in excess of par value	**16,330**	16,041	15,713	15,497	15,156
Retained earnings	**181,578**	184,987	173,677	159,730	140,399
Accumulated other comprehensive loss	**(4,291)**	(4,859)	(3,579)	(6,369)	(6,022)
Deferred compensation and benefit plan trust	**(240)**	(240)	(240)	(282)	(298)
Treasury stock, at cost	**(42,493)**	(42,733)	(38,290)	(33,884)	(29,685)
Total Chevron Corporation Stockholders' Equity	**152,716**	155,028	149,113	136,524	121,382
Noncontrolling interests	**1,170**	1,163	1,314	1,308	799
Total Equity	**153,886**	156,191	150,427	137,832	122,181
Total Liabilities and Equity	**$266,103**	$266,026	$253,753	$232,982	$209,474

Segment Assets

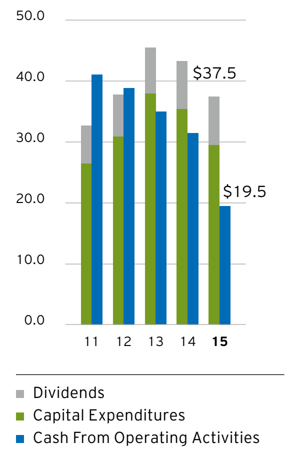
Millions of dollars	At December 31 2015	2014	2013	2012	2011
Upstream[1,2]	**$214,212**	$206,672	$187,298	$162,435	$140,290
Downstream	**36,390**	40,791	44,097	43,047	42,699
Total Segment Assets	**$250,602**	$247,463	$231,395	$205,482	$182,989
All Other[2]	**15,501**	18,563	22,358	27,500	26,485
Total Assets	**$266,103**	$266,026	$253,753	$232,982	$209,474
[1] Includes goodwill associated with the acquisition of Unocal Corporation in 2005 and Atlas Energy, Inc., in 2011:	**$ 4,588**	$ 4,593	$ 4,639	$ 4,640	$ 4,642

[2] 2012 to 2014 conformed to 2015 presentation.

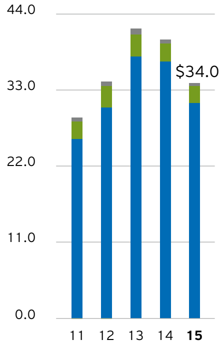
Consolidated Statement of Cash Flows

Millions of dollars	Year ended December 31 2015	2014	2013	2012	2011
Operating Activities					
Net income	**$ 4,710**	$ 19,310	$ 21,597	$ 26,336	$ 27,008
Adjustments:					
Depreciation, depletion and amortization	**21,037**	16,793	14,186	13,413	12,911
Dry hole expense	**2,309**	875	683	555	377
Distributions less than income from equity affiliates	**(760)**	(2,202)	(1,178)	(1,351)	(570)
Net before-tax gains on asset retirements and sales	**(3,215)**	(3,540)	(639)	(4,089)	(1,495)
Net foreign currency effects	**(82)**	(277)	(103)	207	(103)
Deferred income tax provision	**(1,861)**	1,572	1,876	2,015	1,589
Net (increase) decrease in operating working capital	**(1,979)**	(540)	(1,331)	363	2,318
(Increase) decrease in long-term receivables	**(59)**	(9)	183	(169)	(150)
Decrease (increase) in other deferred charges	**25**	263	(321)	1,047	341
Cash contributions to employee pension plans	**(868)**	(392)	(1,194)	(1,228)	(1,467)
Other	**199**	(378)	1,243	1,713	336
Net Cash Provided by Operating Activities	**19,456**	31,475	35,002	38,812	41,095
Investing Activities					
Acquisition of Atlas Energy	**–**	–	–	–	(3,009)
Advance to Atlas Energy	**–**	–	–	–	(403)
Capital expenditures	**(29,504)**	(35,407)	(37,985)	(30,938)	(26,500)
Proceeds and deposits from asset sales	**5,739**	5,729	1,143	2,777	3,517
Net maturities of (investments in) time deposits	**8**	–	700	3,250	(1,104)
Net sales (purchases) of marketable securities	**122**	(148)	3	(3)	(74)
Net (borrowing) repayment of loans by equity affiliates	**(217)**	140	314	328	339
Net sales (purchases) of other short-term investments	**44**	(207)	216	(210)	(255)
Net Cash Used for Operating Activities	**(23,808)**	(29,893)	(35,609)	(24,796)	(27,489)
Financing Activities					
Net (repayments) borrowings of short-term obligations	**(335)**	3,431	2,378	264	23
Proceeds from issuances of long-term debt	**11,091**	4,000	6,000	4,007	377
Repayments of long-term debt and other financing obligations	**(32)**	(43)	(132)	(2,224)	(2,769)
Cash dividends – common stock	**(7,992)**	(7,928)	(7,474)	(6,844)	(6,136)
Distributions to noncontrolling interests	**(128)**	(47)	(99)	(41)	(71)
Net sales (purchases) of treasury shares	**211**	(4,412)	(4,494)	(4,142)	(3,193)
Net Cash Provided by (Used for) Financing Activities	**2,815**	(4,999)	(3,821)	(8,980)	(11,769)
Effect of exchange rate changes on cash and cash equivalents	**(226)**	(43)	(266)	39	(33)
Net Change in Cash and Cash Equivalents	**(1,763)**	(3,460)	(4,694)	5,075	1,804
Cash and cash equivalents at January 1	**12,785**	16,245	20,939	15,864	14,060
Cash and Cash Equivalents at December 31	**$ 11,022**	$ 12,785	$ 16,245	$ 20,939	$ 15,864

Cash From Operating Activities Compared With Capital Expenditures & Dividends
Billions of dollars



Capital & Exploratory Expenditures*
Billions of dollars



*Includes equity share in affiliates.

Capital and Exploratory Expenditures

(Includes equity share in affiliates)

Millions of dollars	2015	2014	2013	2012	2011*
					Year ended December 31
United States					
Exploration	**$ 1,680**	$ 1,391	$ 1,184	$ 1,827	$ 528
Production	**5,874**	7,354	7,221	6,634	7,767
Other Upstream	**28**	54	75	70	23
Refining	**405**	373	889	1,215	964
Marketing	**76**	66	67	110	80
Chemicals	**1,354**	1,025	723	323	278
Other Downstream	**88**	185	307	265	139
All Other	**418**	584	821	602	575
Total United States	**9,923**	11,032	11,287	11,046	10,354
International					
Exploration	**1,339**	2,131	3,994	2,366	1,690
Production	**21,735**	25,228	23,964	18,075	14,400
Other Upstream	**461**	957	1,420	1,472	1,464
Refining	**131**	309	434	627	611
Marketing	**130**	254	304	283	226
Chemicals	**110**	150	223	148	93
Other Downstream	**142**	228	228	201	220
All Other	**8**	27	23	11	8
Total International	**24,056**	29,284	30,590	23,183	18,712
Worldwide					
Exploration	**3,019**	3,522	5,178	4,193	2,218
Production	**27,609**	32,582	31,185	24,709	22,167
Other Upstream	**489**	1,011	1,495	1,542	1,487
Refining	**536**	682	1,323	1,842	1,575
Marketing	**206**	320	371	393	306
Chemicals	**1,464**	1,175	946	471	371
Other Downstream	**230**	413	535	466	359
All Other	**426**	611	844	613	583
Total Worldwide	**$ 33,979**	$ 40,316	$ 41,877	$ 34,229	$ 29,066
Memo: Equity share of affiliates' expenditures included above	**$ 3,397**	$ 3,467	$ 2,698	$ 2,117	$ 1,695

* Excludes $4.5 billion acquisition of Atlas Energy, Inc.

Exploration Expenses[1]

Millions of dollars	2015	2014	2013	2012	2011
					Year ended December 31
Geological and geophysical	**$ 372**	$ 404	$ 493	$ 499	$ 391
Unproductive wells drilled	**2,309**	875	683	555	377
Other[2]	**659**	706	685	674	448
Total Exploration Expenses	**$ 3,340**	$ 1,985	$ 1,861	$ 1,728	$ 1,216
Memo: United States	**$ 1,624**	$ 586	$ 555	$ 244	$ 198
International	**1,716**	1,399	1,306	1,484	1,018

[1] Consolidated companies only. Excludes amortization of undeveloped leaseholds.
[2] Includes expensed well contributions, oil and gas lease rentals, and research and development costs.

Properties, Plant and Equipment

(Includes capital leases)

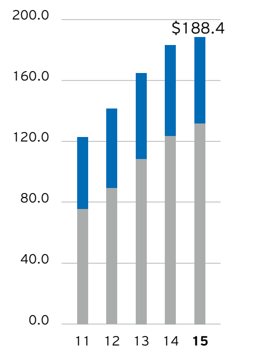
Millions of dollars	2015	2014	2013	2012	2011
	At December 31				
Net Properties, Plant and Equipment at January 1	**$ 183,173**	$ 164,829	$ 141,348	$ 122,608	$ 104,504
Additions at Cost					
Upstream[1]	**26,579**	34,608	35,571	29,554	30,126
Downstream	**1,061**	1,118	1,807	4,042	1,669
All Other[2]	**362**	606	744	419	596
Total Additions at Cost	**28,002**	36,332	38,122	34,015	32,391
Depreciation, Depletion and Amortization Expense[3]					
Upstream	**(18,666)**	(14,051)	(12,157)	(11,435)	(10,893)
Downstream	**(1,228)**	(1,271)	(1,138)	(1,094)	(1,119)
All Other[2]	**(428)**	(589)	(264)	(255)	(271)
Total Depreciation, Depletion and Amortization Expense	**(20,322)**	(15,911)	(13,559)	(12,784)	(12,283)
Net Retirements and Sales					
Upstream	**(616)**	(1,829)	(107)	(824)	(778)
Downstream	**(94)**	(251)	(293)	(400)	(1,185)
All Other[2]	**(182)**	(85)	(55)	(191)	(37)
Total Net Retirements and Sales	**(892)**	(2,165)	(455)	(1,415)	(2,000)
Net Intersegment Transfers and Other Changes[4]					
Upstream[5]	**(1,503)**	131	(603)	(72)	(116)
Downstream	**(80)**	22	(19)	(1,003)	26
All Other[2]	**18**	(65)	(5)	(1)	86
Total Net Intersegment Transfers and Other Changes	**(1,565)**	88	(627)	(1,076)	(4)
Net Properties, Plant and Equipment at December 31					
Upstream[6]	**170,584**	164,790	145,931	123,227	106,004
Downstream	**14,897**	15,238	15,620	15,263	13,718
All Other[2]	**2,915**	3,145	3,278	2,858	2,886
Total Net Properties, Plant and Equipment at December 31	**$ 188,396**	$ 183,173	$ 164,829	$ 141,348	$ 122,608
Memo: Gross properties, plant and equipment	**$ 340,277**	$ 327,289	$ 296,433	$ 263,481	$ 233,432
Accumulated depreciation, depletion and amortization	**(151,881)**	(144,116)	(131,604)	(122,133)	(110,824)
Net properties, plant and equipment	**$ 188,396**	$ 183,173	$ 164,829	$ 141,348	$ 122,608

[1] Net of exploratory well write-offs.
[2] All Other is primarily corporate administrative functions, insurance operations, real estate activities and technology companies.
[3] Difference between the total depreciation, depletion and amortization (DD&A) and total DD&A expense shown on the income statement relates to accretion expense. Reconciliation as follows:

	2015	2014	2013	2012	2011
DD&A on consolidated statement of income	**$ 21,037**	$ 16,793	$ 14,186	$ 13,413	$ 12,911
Less: Accretion expense	**(715)**	(882)	(627)	(629)	(628)
DD&A – Properties, plant and equipment	**$ 20,322**	$ 15,911	$ 13,559	$ 12,784	$ 12,283

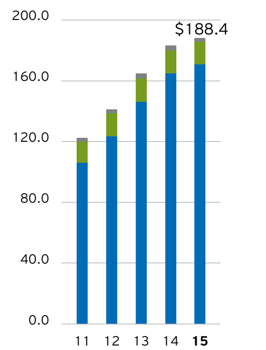
[4] Includes reclassifications to/from other asset accounts.
[5] Includes reclassification adjustments for "Assets held for sale" in 2013 and 2014.
[6] Includes net investment in unproved oil and gas properties. **$ 13,550** $ 14,490 $ 15,703 $ 13,882 $ 12,000

Net Properties, Plant & Equipment by Geographic Area
Billions of dollars



■ United States
■ International

Net Properties, Plant & Equipment by Function
Billions of dollars



■ All Other
■ Downstream
■ Upstream

Upstream >

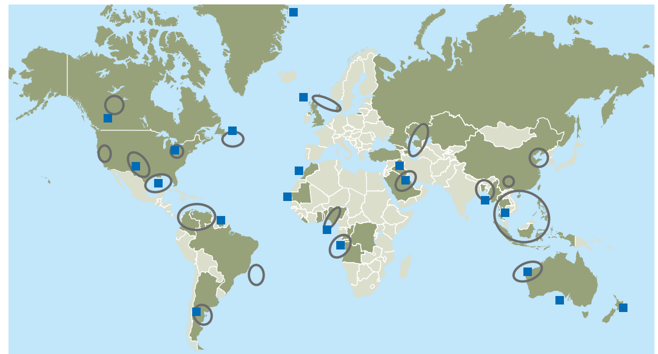
Grow profitably in core areas and build new legacy positions.

Photo: Aerial view of the 15.6 million-metric-ton-per-year Gorgon liquefied natural gas facility on Barrow Island.

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.

Upstream Portfolio Overview



■ Exploration Areas ○ Production

Business Strategies

Grow profitably in core areas and build new legacy positions by:

- Achieving world-class operational performance.
- Maximizing and growing the base business.
- Leading the industry in selection and execution of major capital projects.
- Achieving superior exploration success.
- Commercializing the equity gas resource base.
- Identifying, capturing and effectively incorporating new core upstream businesses.

Industry Conditions

The price of crude oil has fallen significantly since mid-year 2014, reflecting persistently high global crude oil inventories and production. The spot price for West Texas Intermediate (WTI) crude oil averaged $49 per barrel for full-year 2015, compared with $93 in 2014. The Brent price averaged $52 per barrel for full-year 2015, compared with $99 in 2014. As of early March 2016, the WTI and Brent prices were $36 per barrel and $34 per barrel, respectively. The majority of the company's equity crude production is priced based on the Brent benchmark. WTI traded at a discount to Brent throughout 2015 due to high inventories and excess crude supply in the U.S. market. With the lifting of the U.S. crude oil export ban in December 2015, the spread between WTI and Brent narrowed substantially, and WTI traded around parity into March. In response to the volatile crude price environment, the company has significant efforts under way to lower its cost structure and capital spend rate 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 $2.62 per thousand cubic feet (MCF) in 2015, compared with $4.28 per MCF in 2014. 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 is investing in long-term projects to install infrastructure 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. Approximately 85 percent of the equity LNG offtake from the operated Australian LNG projects is targeted to be sold into 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 2015, Chevron's international natural gas realizations averaged $4.53 per MCF, compared with $5.78 per MCF during 2014.

Financial and Operational Highlights

In 2015, Chevron's upstream business achieved record lows in loss of containment incidents while matching last year's record low total-recordable-incident rate. Financial results were down substantially, with a net loss of $2.0 billion. Production of 2.622 million oil-equivalent barrels per day was 2 percent higher than net oil-equivalent production in 2014. Project ramp-ups in the United States and Bangladesh and production entitlement effects in several locations were offset by the Partitioned Zone shut-in, normal field declines and the effect of asset sales. Upstream capital and exploratory expenditures were $31.1 billion in 2015. Portfolio management activities resulted in proceeds of $1.8 billion, primarily related to the sale of upstream interests in Nigeria, Vietnam and mature U.S. midcontinent assets. In 2016, the upstream capital and exploratory budget is $24.0 billion. Approximately $9 billion of planned capital spending is for base business assets, which include shale and tight resource investments. Roughly $11 billion is related to the construction of major capital projects already under way, and approximately $3 billion is for projects that have not achieved a final investment decision. Exploration funding accounts for approximately $1 billion. The company will continue to monitor crude oil market conditions and will further restrict capital outlays should current oil price conditions persist.

Upstream Financial and Operating Highlights

(Includes equity share in affiliates)

Dollars in Millions	2015	2014
Earnings	**$ (1,961)**	$ 16,893
Net liquids production (Thousands of barrels per day)	**1,744**	1,709
Net natural gas production (Millions of cubic feet per day)	**5,269**	5,167
Net oil-equivalent production (Thousands of barrels per day)	**2,622**	2,571
Net proved reserves* (Millions of barrels of oil-equivalent)	**11,168**	11,102
Net unrisked resource base* (Billions of barrels of oil-equivalent)	**68**	67
Capital and exploratory expenditures	**$ 31,117**	$ 37,115

* For definitions of reserves and resources, refer to pages 50 and 51, respectively.

Exploration and Portfolio Additions

The company made several important portfolio additions in 2015 and early 2016. Offshore acreage was acquired in Canada, Mauritania, Myanmar, New Zealand and the U.S. Gulf of Mexico. Unconventional acreage was added in core areas of the Marcellus/Utica trend in the United States.

The company's focus areas for exploration drilling in 2015 were the deepwater regions of West Africa, the deepwater U.S. Gulf of Mexico, offshore northwest Australia, and several shale and tight resource plays in North America. Exploration activity, including drilling and seismic acquisition, was ongoing in several other areas, including Argentina, offshore southern Australia, the eastern coast of Canada, China, Greenland, the Kurdistan Region of Iraq, Morocco, Myanmar, the Partitioned Zone, Thailand and offshore United Kingdom. The company's exploration activities have added 11.3 billion barrels of potentially recoverable oil-equivalent resources since 2006.

2015 Accomplishments:

- Achieved an exploration drilling success rate of 62 percent with 36 discoveries worldwide and added 1.8 billion barrels of potentially recoverable oil-equivalent resources.
- Australia – Made a natural gas discovery at the Isosceles prospect in the Carnarvon Basin offshore Western Australia, contributing to the resources available to extend and expand the company's LNG projects.
- Canada – Acquired an interest in a Flemish Pass Basin block, offshore Atlantic Canada.
- Mauritania – Discovered natural gas at the deepwater Marsouin prospect.
- United States – Discovered crude oil at the Sicily prospect in the deepwater Gulf of Mexico.
- United States – Added 13 deepwater leases in the central Gulf of Mexico.

2016 Outlook:

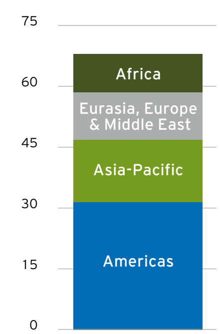
During 2016, the company plans to invest approximately $1 billion in exploration activities and to drill more than 35 exploration and appraisal wells worldwide, including eight impact wells (a well with a predrill unrisked resource potential of greater than 100 million barrels of oil-equivalent). The program reduces exploration spend while supporting continued exploration and appraisal activity in the U.S. Gulf of Mexico, Western Australia, West Africa, and shale and tight resource plays in the Permian Basin and Canada. This planned spending also includes evaluation of recently acquired acreage, including Argentina, Atlantic Canada, Mauritania, Morocco, Myanmar, New Zealand and South Australia.

Resources and Proved Reserves

The company's net unrisked resource base at year-end 2015 increased to 68 billion barrels of oil-equivalent, up 1 percent from year-end 2014. Extensions and discoveries in the United States, Australia and Africa more than offset production, divestments and technical revisions. Included in the resource base are 11.2 billion barrels of net proved oil-equivalent reserves at year-end 2015.

The resources are well diversified across geographic regions, with 28 percent located in the United States, 13 percent in Australia, 10 percent in Canada, and 9 percent in both Kazakhstan and 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 170 trillion cubic feet of unrisked natural gas resources globally, with about half located in Australia and Asia, and is well situated to supply anticipated growth in Asia-Pacific natural gas demand.

2015 Net Unrisked Resources by Region*
Billions of oil-equivalent barrels



*Refer to page 51 for definition of resources.

Base Business

Continued development of the base business is critical to maintaining the company's crude oil and natural gas production. Through targeted investment in small capital projects and a consistent focus on operating efficiency, maintenance and reliability, the company has been successful in limiting the annual rate of production decline in the base business to less than 2 percent. Application of technology is instrumental to the success of the base business. In 2015, Chevron completed deployment of INTERSECT, a new reservoir simulation software, to all major capital projects and key producing assets, enabling coupled reservoir and surface network modeling and fully integrated analysis of static and dynamic uncertainties, resulting in more reliable production forecasts and optimized project performance. The company's Real-Time Reservoir Management system provides a common data platform that optimizes surveillance and management of the company's reservoirs, allowing for faster and more thorough analysis and improved decision making. Initiatives to improve operating efficiencies, invest in targeted growth and fully leverage existing facilities are planned to continue in 2016. An increase in the base business decline rate is expected in the coming years due to reduced investment.

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 and in Argentina and Canada. Spending is focused on the liquids-rich shale formations in the Permian Basin, the Vaca Muerta Shale in Argentina and the Duvernay Shale in Canada. The company is focused on identifying the areas most prospective for development and bringing those resources to production safely and cost effectively.

Shale and Tight Resources – Key Areas

Location	Basin or Play	Net Acreage (Thousands of acres)
Argentina	Vaca Muerta	167
Canada	Duvernay	228
Canada	Liard/Horn River	300
United States	Marcellus	600
United States	Permian (Delaware Basin)	1,000
United States	Permian (Midland Basin)	500
United States	Utica	320

Major Capital Projects

Production growth is dependent on bringing resources and reserves into production through the successful development of major capital projects. The company has a robust queue of major capital projects expected to sustain the company's production growth. Some of these projects are building legacy positions in natural gas through LNG infrastructure.

2015 Accomplishments:

- Angola – Achieved start-up of the Nemba Enhanced Secondary Recovery (ESR) Stage 1 & 2 Project.
- Angola – Progressed construction of the Mafumeira Sul Project.
- Angola – Progressed work on plant modifications and capacity and reliability enhancements at the Angola LNG Project.
- Angola–Republic of Congo Joint Development Area – Achieved first production at the Lianzi Project.
- Australia – Progressed commissioning activities on LNG Train 1 at the Gorgon Project. Completed installation of all modules for Train 2 at Barrow Island.
- Australia – Progressed construction of the Wheatstone Project. Completed delivery of all modules required for LNG Train 1 start-up.
- Nigeria – Achieved first production at Agbami 3.
- Nigeria – Achieved start-up of Escravos Gas Plant Phase 3B.
- Republic of Congo – Commenced production at the Moho Nord Project to the existing Moho-Bilondo floating production unit.
- United States – Commenced front-end engineering and design for the Tahiti Vertical Expansion Project.

2016 Outlook:

- Angola – Commence production at the Mafumeira Sul Project.
- Angola – Resume LNG production at the Angola LNG Project.
- Angola – Achieve start-up of the Congo River Canyon Crossing Pipeline supporting Angola LNG.
- Australia – Achieve start-up of LNG Trains 1 and 2 at the Gorgon Project. (Train 1 start-up was achieved in March 2016.)
- Australia – Continue construction of the Wheatstone Project.
- China – Commence production from the Xuanhan Gas Plant at the Chuandongbei Project. (Production commenced in January 2016.)
- Kazakhstan – Reach final investment decisions for the Future Growth Project and the Wellhead Pressure Management Project at Tengizchevroil (TCO).
- Kazakhstan/Russia – Complete expansion of the Caspian Pipeline Consortium pipeline.
- United Kingdom – Commence production at the Alder Field.
- United States – Reach final investment decision for the Tahiti Vertical Expansion Project.

The projects in the table below are considered the more significant in the development portfolio and have commenced production or are in the design or construction phase. Each project has a 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)
2015					
Angola	Nemba ESR Stage 1 & 2	39.2	Chevron	9[3]	–
Angola-Republic of Congo	Lianzi	31.3	Chevron	46	–
Nigeria	Agbami 3	67.3	Chevron	Maintain capacity	
	Escravos Gas Plant Phase 3B	40.0	Chevron	–	120[4]
Republic of Congo	Moho Nord	31.5	Other	140[3]	–
2016–2018					
Angola	Angola LNG Plant[5]	36.4	Affiliate	63[6]	670[6]
	Mafumeira Sul	39.2	Chevron	150	350
Australia	Gorgon LNG Trains 1-3	47.3	Chevron	20	2,580
	Wheatstone LNG Trains 1-2	80.2/64.1[7]	Chevron	30	1,608
Canada	Hebron	29.6	Other	150	–
China	Chuandongbei Stage 1	49.0	Chevron	–	258[6]
Nigeria	Sonam Field Development	40.0	Chevron	30[3]	215[3]
United Kingdom	Alder	73.7	Chevron	14	110
	Clair Ridge	19.4	Other	120	100
United States	Big Foot	60.0	Chevron	75	25
	Stampede	25.0	Other	80	40
	Jack/St. Malo Stage 2	50.0–51.0	Chevron	Maintain capacity	
2019+					
Canada	Kitimat LNG	50.0	Chevron	–	1,600
Indonesia	Gendalo-Gehem	~63.0	Chevron	47	1,100
Kazakhstan	TCO Future Growth Project	50.0	Affiliate	250-300[3]	–
	TCO Wellhead Pressure Management Project	50.0	Affiliate	Maintain capacity	
United Kingdom	Captain Enhanced Oil Recovery	85.0	Chevron	Maintain capacity	
	Rosebank	40.0	Chevron	100	80
United States	Tahiti Vertical Expansion	58.0	Chevron	Maintain capacity	

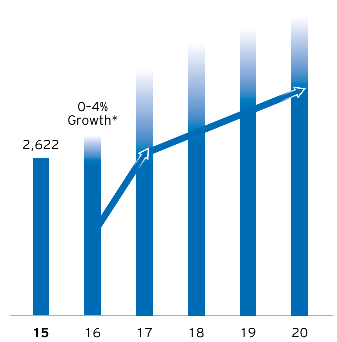
1 MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day.
2 Start-up timing for nonoperated projects per operator's estimate.
3 Represents expected total daily production.
4 Excludes incremental crude oil production enabled by this project.
5 Plant restart in 2016.
6 Represents facility design outlet capacity.
7 Represents the company's ownership in the offshore licenses and LNG facilities, respectively.

Production Outlook

The company's production is expected to grow substantially through the end of the decade as a result of continued investment in major capital projects 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 Jack/St. Malo, Stampede and Big Foot projects in the deepwater Gulf of Mexico; the Gorgon and Wheatstone projects in Australia; the Angola LNG Plant and the Mafumeira Sul Project in Angola; as well as increased production of shale and tight resources in the Permian Basin. Collectively, these investments are expected to increase the portion of production coming from legacy assets having flat or low production declines for a decade or longer. The company estimates its average worldwide net oil-equivalent production in 2016 will be flat to 4 percent growth compared to 2015.

This outlook for future production levels is subject to many factors and uncertainties, including, among other things, the duration of the low price environment that began in second-half 2014; production quotas or other actions that might be imposed by OPEC; 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
Thousands of oil-equivalent barrels per day



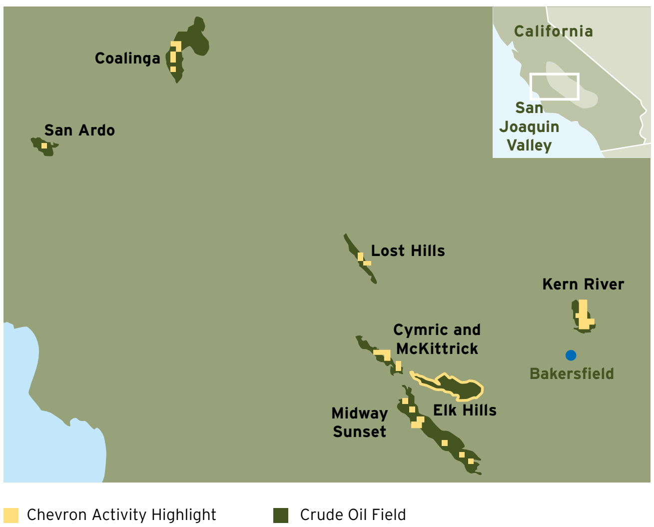
*Includes estimated impact of divestments.

United States

Chevron's U.S. portfolio encompasses a diverse group of assets primarily located in California, the Gulf of Mexico, Colorado, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming. The company was one of the largest liquids producers in the United States in 2015, with net daily oil-equivalent production averaging 720,000 barrels, representing 27 percent of the companywide total.

California

Located primarily in the San Joaquin Valley with more than 16,000 wells in operation, Chevron ranked No. 1 in net daily oil-equivalent production in California in 2015 at 179,000 barrels, composed of 166,000 barrels of crude oil, 61 million cubic feet of natural gas and 3,000 barrels of natural gas liquids (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 industry-leading 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 leading-edge heat management capabilities in the recovery of these hydrocarbons, with emphasis on improved energy efficiency through new technology and processes. An active development drilling program and increased steam injection have helped reverse the decline rate on company-operated properties from 7 percent in 2010 to a 2 percent increase in 2015.

Chevron also holds an average nonoperated working interest of approximately 23 percent in four producing zones at the Elk Hills Field.

Gulf of Mexico

During 2015, net daily production in the Gulf of Mexico averaged 164,000 barrels of crude oil, 315 million cubic feet of natural gas and 16,000 barrels of NGLs. As of early 2016, Chevron has an interest in 474 leases in the Gulf of Mexico, 345 of which are located in water depths greater than 1,000 feet (305 m). At the end of 2015, the company was the largest leaseholder in the Gulf of Mexico.

Shelf

Chevron is the largest producer of crude oil and natural gas on the Gulf of Mexico shelf. Average net daily production in 2015 was 45,000 barrels of crude oil, 218 million cubic feet of natural gas and 6,000 barrels of NGLs. The company drilled 41 development and delineation wells during 2015. The company is pursuing selected opportunities for divestment.

Deep Water

Chevron is one of the top leaseholders in the deepwater Gulf of Mexico. Average net daily production in 2015 was 119,000 barrels of crude oil, 97 million cubic feet of natural gas and 10,000 barrels of NGLs, primarily from the Blind Faith, Caesar/Tonga, Jack, St. Malo, Tahiti and Tubular Bells fields and the Perdido Regional Development.

Marine Well Containment Company LLC, a not-for-profit company sponsored by Chevron and other major energy companies, commissioned its expanded containment system in third quarter 2015. The expanded system replaces the interim containment system and provides increased capacity and compatibility with a wider range of well designs, flow rates and environmental conditions.

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. 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 2015 averaged 61,000 barrels of liquids (31,000 net) and 10 million cubic feet of natural gas (5 million net). Production ramp-up and development drilling for the first development phase continued in 2015.

Photo: Production ramp-up continued at the Jack/St. Malo semi-submersible floating production unit.

Work continued during 2015 on the evaluation of additional development opportunities for the Jack and St. Malo fields. Stage 2, the second phase of the development plan, includes four additional development wells, two each at the Jack and the St. Malo fields. Front-end engineering and design (FEED) activities for Stage 2 were completed in September 2015. Drilling commenced in October 2015 and is planned to continue in 2016. First oil from Stage 2 is expected in 2017, and proved reserves have been recognized for this project.

Production from the Jack/St. Malo development is expected to ramp up to a total daily rate of 94,000 barrels of crude oil and 21 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 substantially increase incremental recovery from these fields.

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 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. The field has an estimated production life of 35 years from the time of start-up, and total potentially recoverable oil-equivalent resources are estimated to exceed 200 million barrels. Proved reserves have been recognized for this project.

Work to install the platform was suspended in second quarter 2015 when nine of 16 mooring tendons lost buoyancy. The remaining tendons were recovered, and the platform was moved to a safe harbor location. First oil is expected in second-half 2018.

Tahiti In 2015, net daily production averaged 31,000 barrels of crude oil, 12 million cubic feet of natural gas and 2,000 barrels of NGLs at the 58 percent-owned and operated Tahiti Field. The next development phase, the Tahiti Vertical Expansion Project, entered FEED in mid-2015, and a final investment decision is expected mid-2016. At the end of 2015, proved reserves had not been recognized for the Tahiti Vertical Expansion Project. The Tahiti Field has an estimated remaining production life of at least 20 years.

Tubular Bells In 2015, net daily production averaged 10,000 barrels of crude oil and 20 million cubic feet of natural gas at the Tubular Bells Field, where Chevron holds a 42.9 percent nonoperated working interest. Development drilling continued during 2015.

Mad Dog Chevron has a 15.6 percent nonoperated working interest in the Mad Dog Field. In 2015, net daily production averaged 4,000 barrels of liquids and 1 million cubic feet of natural gas. The placement of surface casing on five planned infill wells was completed in 2014, and the first well commenced production in fourth quarter 2015.

The next development phase, the Mad Dog 2 Project, is planned to develop the southern portion of the Mad Dog Field. The development plan was re-evaluated, and FEED was re-entered on a new development concept in 2014. FEED activities continued in 2015. The total potentially recoverable oil-equivalent resources for Mad Dog 2 are estimated to exceed 500 million barrels. At the end of 2015, proved reserves had not been recognized for the Mad Dog 2 Project.

Stampede Chevron holds a 25 percent nonoperated working interest in the Stampede Project, the unitized development of the Knotty Head and Pony discoveries. The field is located in the Green Canyon area, in a water depth of 3,500 feet (1,067 m) with a reservoir depth of approximately 30,000 feet (9,144 m). The development plan includes a tension leg platform with design capacity to produce 80,000 barrels of crude oil and 40 million cubic feet of natural gas per day. Development drilling commenced in fourth quarter 2015, with first oil expected in 2018. The field has an estimated production life of 30 years from the time of start-up and total potentially recoverable oil-equivalent resources estimated to exceed 300 million barrels. Proved reserves have been recognized for this project.

Buckskin/Moccasin FEED activities progressed in 2015 on a project to jointly develop the 55 percent-owned and operated Buckskin Field and the 87.5 percent-owned and operated Moccasin Field. A decision was made in fourth quarter 2015 not to pursue the development. In January 2016, the company relinquished its interest in Moccasin and transferred the operatorship of Buckskin to another working interest partner. The company plans to transfer its interest in Buckskin to the other working interest owners in 2016.

Exploration During 2015 and early 2016, the company participated in nine deepwater wells, five appraisal and four exploration. Drilling was completed at the 50 percent-owned and operated Sicily exploration well in second quarter 2015, which resulted in a crude oil discovery. Drilling commenced on an appraisal well at Sicily in December 2015. Appraisal activities, including a sidetrack of the discovery well, at the 55 percent-owned and operated Anchor discovery were completed in fourth quarter 2015 and were successful. Drilling commenced on an additional appraisal well at Anchor in first quarter 2016.

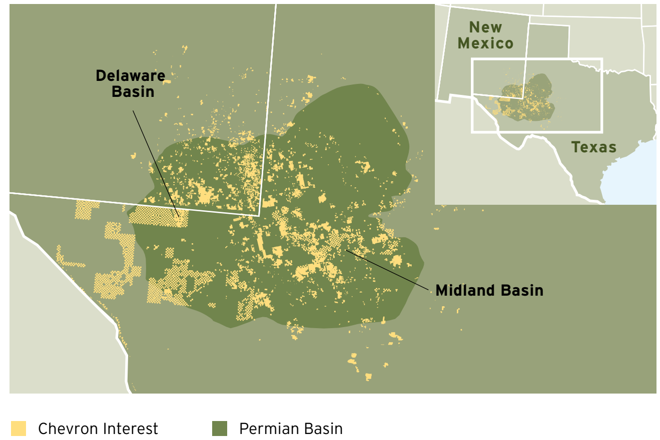
Chevron is the operator of an exploration and appraisal program covering 28 jointly held offshore leases in the northwest portion of Keathley Canyon. The resource potential in this area may enable a cost-effective, multifield hub development of the Guadalupe and Tiber discoveries, with the potential addition of the Gibson prospect. This potential development, named Tigris, is under evaluation as exploration and appraisal work progresses. Drilling of a sidetrack at the 36 percent-owned and operated Gila discovery well was completed in third quarter 2015. The Gila prospect was deemed noncommercial, and two of the leases were relinquished in early 2016. Drilling commenced at a 36 percent-owned and operated Gibson exploration well in fourth quarter 2015 and is planned to be completed in second quarter 2016.

Chevron added 13 leases to the deepwater portfolio as a result of awards from the central Gulf of Mexico Lease Sale 235, held in first quarter 2015.

Midcontinent

The company produces crude oil and natural gas in the midcontinent region of the United States, primarily in Colorado, New Mexico, Oklahoma, Texas and Wyoming. In 2015, the company's net daily production in these areas averaged 116,000 barrels of crude oil, 600 million cubic feet of natural gas and 34,000 barrels of NGLs. The company is pursuing selected opportunities for divestment.

The company's most significant holdings in the midcontinent region are in the Permian Basin of West Texas and southeast New Mexico. The Permian is composed of several basins, including the liquids-rich Midland and Delaware basins, and it offers both conventional and shale and tight resource opportunities. Chevron is the largest net acreage leaseholder and one of the largest producers in the Permian. Average net daily production in 2015 was 96,000 barrels of crude oil, 320 million cubic feet of natural gas and 25,000 barrels of NGLs. The total potentially recoverable oil-equivalent resources from the company's acreage in the Permian Basin are estimated at 9 billion barrels.



Conventional Resources

Chevron actively manages declines in its conventional oil and gas assets in the midcontinent region, including on its 400,000 net acres (1,619 sq km) in the Central Basin Platform of the Permian Basin. Substantial hydrocarbons are recoverable through secondary and tertiary methods that increase ultimate recovery and offset field decline. 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.

Shale and Tight Resources

Chevron's capital spending on exploration and development of the approximately 1.5 million net acres (6,070 sq km) of shale and tight resources in the Midland and Delaware basins is focused on horizontal wells with multistage fracture stimulation. Because of the company's strong legacy position in the Permian Basin, 85 percent of its leases have either low or no royalty payments, providing a significant competitive advantage. With multiple stacked tight oil zones, the area is poised to deliver significant long-term growth for Chevron. The stacked plays enable efficient development and production from multiple zones and utilization of existing infrastructure. The company's development activities in the Permian are focused in the Delaware and Midland basins where significant recoverable oil-equivalent resources have been added and additional exploration opportunities have been identified. The company also holds shale and tight resource opportunities elsewhere in the midcontinent region, primarily in East Texas and the Piceance Basin in northwestern Colorado.

Midland Basin The company holds approximately 500,000 net acres (2,023 sq km) in the Midland Basin. A total of four company-operated rigs were active at year-end 2015, and there were 115 company-operated wells drilled during the year. The company also participated in 72 nonoperated wells during 2015 with three nonoperated rigs active at year-end.

Photo: The focus shifted to horizontal multiwell pad drilling in the Midland and Delaware basins during 2015.

Delaware Basin Chevron is the largest acreage holder in the Delaware Basin, with approximately 1.0 million net acres (4,047 sq km). A total of 32 company-operated wells were drilled during the year, and a total of two company-operated rigs were active at year-end. The company also participated in 108 nonoperated wells during 2015, with 11 nonoperated rigs active at year-end. Five of the nonoperated rigs were active at the company's two joint development agreement areas in the Delaware Basin that include access to related infrastructure. These operated and nonoperated development activities have defined multiple liquids-rich stacked plays.

Appalachian Basin/Michigan

The company is a significant leaseholder in the Marcellus Shale and the Utica Shale, primarily located in southwestern Pennsylvania, eastern Ohio and the West Virginia panhandle. In 2015, the company's net daily production in these areas averaged 334 million cubic feet of natural gas.

Marcellus Shale In the Marcellus Shale, the company holds approximately 600,000 net acres (2,428 sq km). During 2015, 56 development wells were drilled, primarily funded by a 75 percent drilling carry. The company had two drilling rigs in operation at year-end. Development is proceeding at a measured pace and was focused on improving execution capability, well performance and cost effectiveness.

Utica Shale The company holds a significant position in the Utica Shale, with approximately 320,000 net acres (1,295 sq km). Activity during 2015 included the drilling of two exploratory wells. This activity was focused on acquiring data necessary for potential future development.

Antrim Shale In Michigan, the company holds approximately 370,000 net acres (1,497 sq km) in the Antrim Shale and Collingwood/Utica Shale formations, with production from approximately 2,800 wells in the Antrim.

Other Americas

In Other Americas, the company is engaged in upstream activities in Argentina, Brazil, Canada, Colombia, Greenland, Suriname, Trinidad and Tobago, and Venezuela. Net daily oil-equivalent production of 224,000 barrels during 2015 in these countries represented 9 percent of the companywide total.

Canada

Chevron has interests in oil sands projects 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 exploration and discovered resource interests in the Beaufort Sea region of the Northwest Territories. Net daily production in 2015 from Canadian operations was 20,000 barrels of crude oil, 14 million cubic feet of natural gas and 47,000 barrels of synthetic oil from oil sands.

Chevron Activity Highlight   Crude Oil Field   Oil Sands
Proposed Terminal

Atlantic Canada

Hibernia Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field that comprises two key reservoirs, Hibernia and Ben Nevis Avalon. Production declines continue to be mitigated through drilling programs in both reservoirs. Average net daily crude oil production in 2015 was 20,000 barrels.

Chevron also has a 23.6 percent nonoperated working interest in the unitized Hibernia Southern Extension areas of the Hibernia Field, where production start-up was achieved in 2015.

Hebron Chevron holds a 29.6 percent nonoperated working interest in the Hebron Field development, which includes a concrete, gravity-based platform with a design capacity of 150,000 barrels of crude oil per day. Construction of the platform structure and topsides continued during 2015. This heavy oil field is estimated to contain total potentially recoverable oil-equivalent resources of more than 600 million barrels. The project has an expected economic life of 30 years from the time of start-up, and first oil is expected in 2017. Proved reserves have been recognized for this project.

Exploration In the Flemish Pass Basin, Chevron holds a 40 percent nonoperated working interest in two exploration blocks, EL 1125 and EL 1126, totaling 321,000 net acres (1,300 sq km). A 3-D seismic survey has been completed on these blocks. Drilling commenced at the Fitzroya prospect in fourth quarter 2015 and was completed in late February 2016, and the results are under evaluation.

In November 2015, the company was awarded a 35 percent interest in another Flemish Pass Basin block, NL 15-01-02, with 237,000 net acres (959 sq km). Chevron is the operator.

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. In 2015, average net daily synthetic oil production was 47,000 barrels. Construction progressed during 2015 on the Quest Project, and the project was commissioned in the fourth quarter. The Quest Project is designed to capture and store more than 1 million tons of carbon dioxide produced annually by AOSP bitumen processing.

Duvernay Shale The company holds 228,000 net acres (923 sq km) in the Duvernay Shale in Alberta and approximately 200,000 overlying acres (809 sq km) in the Montney tight rock formation. Chevron has a 70 percent-owned and operated interest in most of the Duvernay acreage. Production from the initial wells in the Duvernay continued to demonstrate good flow rates and high condensate yields from these tight resources. Drilling continued during 2015 on an expanded 16-well appraisal program. A total of 28 wells had been tied into production facilities by early 2016.

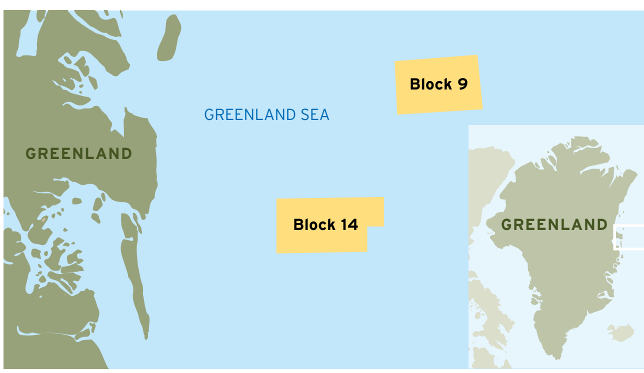
Photo: Drilling continued during 2015 on an expanded 16-well appraisal program in the Duvernay Shale.

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 interest in 300,000 net acres (1,214 sq km) in the Horn River and Liard shale gas basins in British Columbia. Chevron assumed operatorship of the upstream portion of the project in May 2015 and continued with the horizontal appraisal drilling program that began in 2014. 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 2015, proved reserves had not been recognized for the Kitimat LNG Project.

Gas Storage Facilities The company holds a 93.8 percent operated interest in the Aitken Creek and a 42.9 percent nonoperated interest in the Alberta Hub natural gas storage facilities, which have an aggregate total capacity of approximately 100 billion cubic feet. These facilities are located adjacent to several shale gas plays. The company is pursuing opportunities for divestment of these interests.

Greenland

Chevron holds a 29.2 percent-owned and operated interest in two blocks located in the Kanumas Area, offshore the northeast coast of Greenland. Blocks 9 and 14 are in water depths up to 1,500 feet (450 m) and cover 350,000 net acres (1,417 sq km). Acquisition of 2-D seismic data occurred over the licenses in 2015. Evaluation of the acreage is ongoing.



Chevron Interest

Argentina

In the Vaca Muerta Shale formation — a thick, laterally extensive, liquids-rich shale — Chevron holds a 50 percent nonoperated interest in two concessions covering 73,000 net acres (294 sq km). Chevron also holds an 85 percent-owned and operated interest in one concession covering 94,000 net acres (380 sq km) with both conventional production and Vaca Muerta Shale potential. In addition, the company holds operated interests in three concessions covering 73,000 net acres (294 sq km) elsewhere in the Neuquen Basin, with interests ranging from 18.8 percent to 100 percent. During 2015, Argentina net daily production averaged 21,000 barrels of crude oil and 36 million cubic feet of natural gas.

Loma Campana Development activities continued in 2015 at the Loma Campana concession in the Vaca Muerta Shale, with an average of 13 rigs per month onsite drilling both horizontal and vertical wells. During 2015, 156 wells were drilled, most of which were vertical wells. In 2016, the drilling plan shifts to primarily horizontal wells.

Photo: Development drilling continued in 2015 at the Loma Campana concession.

Exploration During 2015, the company progressed the exploration of shale oil and gas resources in the Narambuena Block in the Chihuido de la Sierra Negra concession, also in the Vaca Muerta Shale. The exploration plan for Narambuena includes a total of nine wells to be drilled in two phases.

Chevron Activity Highlight

Brazil

Chevron holds working interests in the Frade (51.7 percent-owned and operated) and Papa-Terra (37.5 percent nonoperated) deepwater fields located in the Campos Basin. During 2015, net daily production averaged 17,000 barrels of crude oil and 5 million cubic feet of natural gas.

Frade During 2015, net daily production averaged 11,000 barrels of crude oil and 4 million cubic feet of natural gas from the existing 10 producer wells. The concession that includes the Frade Field expires in 2025.

Papa-Terra The producing facilities at the Papa-Terra Field include a floating production, storage and offloading vessel (FPSO) and a tension leg wellhead platform (TLWP). First production from the TLWP occurred in first quarter 2015. Net daily production during 2015 averaged 6,000 barrels of crude oil and 1 million cubic feet of natural gas. The concession expires in 2032.

Exploration Chevron holds a 50 percent-owned and operated interest in Block CE-M715, located in the Ceara Basin offshore equatorial Brazil. The deepwater block covers 40,000 total acres (163 sq km). The acquisition of 3-D seismic data commenced in September 2015.

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 the onshore Ballena natural gas fields and receives 43 percent of the production for the remaining life of each field and a variable production volume based on prior Chuchupa capital contributions. Net daily production in 2015 averaged 161 million cubic feet of natural gas.

Chevron Activity Highlight

Suriname

Chevron holds a 50 percent nonoperated working interest in Blocks 42 and 45 offshore Suriname. The deepwater exploration blocks cover a combined area of approximately 1.4 million acres (5,649 sq km). Farm-down opportunities are being pursued for the two blocks.

Trinidad and Tobago

The company has a 50 percent nonoperated working interest in three blocks (Block E, Block 5(a) and Block 6) in the offshore East Coast Marine Area of Trinidad, which includes the Dolphin, Dolphin Deep and Starfish natural gas fields. Net daily production during 2015 from these fields averaged 116 million cubic feet of natural gas. These volumes were sold under long-term sales contracts to supply the domestic market and for LNG exports.

Venezuela

Chevron's production activities in Venezuela are performed by two affiliates in western Venezuela and one affiliate in the Orinoco Belt, which produces and upgrades heavy oil resources. During 2015, net daily production averaged 30,000 barrels of crude oil, 30 million cubic feet of natural gas and 29,000 barrels of synthetic oil upgraded from heavy oil.

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 2015, net daily production averaged 27,000 barrels of liquids and 5 million cubic feet of natural gas. Thirty development wells were drilled in 2015.

Petroindependiente The company holds a 25.2 percent interest in Petroindependiente, which operates the LL-652 Field in Lake Maracaibo under a contract expiring in 2026.

Petropiar Chevron holds a 30 percent interest in Petropiar, which operates the Hamaca heavy oil production and upgrading project under an agreement expiring in 2033. The project is located in the Orinoco Belt and includes processing and upgrading of extra heavy crude oil (8.5 degrees API gravity) into lighter, higher-value synthetic oil (up to 26 degrees API gravity). Net daily production averaged 29,000 barrels of synthetic crude oil, 2,000 barrels of extra-heavy crude oil and 18 million cubic feet of natural gas during 2015. Forty-one development wells were drilled in 2015. Enhanced oil recovery (EOR) studies continued through the year.

Petroindependencia Chevron holds a 34 percent interest in Petroindependencia, which includes the Carabobo 3 heavy oil project located in three blocks in the Orinoco Belt.

Loran-Manatee Chevron operates and holds a 60 percent interest in Block 2 offshore Venezuela and a 50 percent interest in the Manatee Area of Block 6(d) offshore Trinidad and Tobago. The Loran Field in Block 2 and the Manatee Field in Block 6(d) form a single, cross-border field that lies along the maritime border of Venezuela and Trinidad and Tobago. Cross-border agreements have been signed between the governments of Trinidad and Tobago and Venezuela, and work continued in 2015 on maturing commercial development.

Africa

In Africa, the company is engaged in upstream activities in Angola, Democratic Republic of the Congo, Liberia, Mauritania, Morocco, Nigeria and Republic of Congo. Net daily oil-equivalent production was 412,000 barrels during 2015. This region represented 16 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 interest in a production-sharing contract (PSC) for deepwater Block 14, located west of Block 0. During 2015, net daily production averaged 110,000 barrels of liquids and 55 million cubic feet of natural gas.

Chevron Activity Highlight | Crude Oil Field | Terminal

Block 0

Block 0 is divided into Areas A and B and contains 21 fields that produced a net daily average of 85,000 barrels of liquids in 2015. The Block 0 concession extends through 2030.

Mafumeira Sul The second stage of the Mafumeira Field development includes a central processing facility, two wellhead platforms, approximately 75 miles (121 km) of subsea pipelines, 34 producing wells and 16 water injection wells. The facility has a design capacity of 150,000 barrels of liquids and 350 million cubic feet of natural gas per day. Construction, hook-up and development drilling activities progressed during 2015. First production is planned for second-half 2016, and ramp-up to full production is expected to continue through 2018. The total potentially recoverable oil-equivalent resources are estimated at 300 million barrels. Proved reserves have been recognized for this project.

Photo: Construction, hook-up and development drilling activities progressed during 2015 at the Mafumeira Sul Project.

Nemba Enhanced Secondary Recovery (ESR) Stage 1 & 2
Start-up occurred at ESR Stage 1 & 2 in first quarter 2015. Total daily production in 2015 averaged 7,000 barrels of crude oil (2,000 net). In addition to enhanced secondary recovery, this project eliminated routine flaring at the South Nemba platform.

Block 14

In 2015, net daily production was 25,000 barrels of liquids from Benguela Belize–Lobito Tomboco (BBLT), Belize North, Benguela North, Tombua and Landana fields. Development and production rights for the various producing fields in Block 14 expire between 2023 and 2028.

Natural Gas Commercialization

Natural gas commercialization efforts are expected to monetize a total potentially recoverable resource of more than 3 trillion cubic feet of natural gas and approximately 130 million barrels of liquids through export sales of LNG and NGLs. Major commercialization projects include participation in Angola LNG Limited and the Congo River Canyon Crossing Pipeline.

Angola LNG 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. The plant has the capacity to process 1.1 billion cubic feet of natural gas per day, with expected average total daily sales of 670 million cubic feet of natural gas and up to 63,000 barrels of NGLs. 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. In early 2016, work was completed on plant modifications and capacity and reliability enhancements. The first LNG cargo is expected in second quarter 2016. The remaining economic life of the project is anticipated to be in excess of 20 years.

Congo River Canyon Crossing Pipeline Chevron holds a 38.1 percent interest in the pipeline, which is designed to transport up to 250 million cubic feet per day of natural gas from Blocks 0 and 14 to the Angola LNG plant. The 87-mile (140-km) offshore pipeline crosses under the Congo River subsea canyon. Drilling of the well intersection and installation of the pipeline under the Congo River canyon was completed in mid-2015 and represented the final portion of the pipeline to be completed. Start-up is planned for 2016.

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 Republic of Congo. The Lianzi Project includes four producing wells and three water injection wells with a subsea tieback to the BBLT platform in Block 14. The project has a design capacity of 46,000 barrels of crude oil per day. Fabrication, installation and the first drilling campaign activities were completed in 2015. First production was achieved in fourth quarter 2015. Production from the Lianzi Project is reflected in the totals of Block 14 in Angola and Republic of Congo.

Photo: Production commenced in fourth quarter 2015 at the Lianzi Project with a subsea tieback to the BBLT facilities in Block 14 in Angola.

Democratic Republic of the Congo

Chevron has a 17.7 percent nonoperated working interest in a concession off the coast of Democratic Republic of the Congo. Net daily production in 2015 from 11 fields averaged 2,000 barrels of crude oil.

Republic of Congo

Chevron has a 31.5 percent nonoperated working interest in the offshore Haute Mer permit areas (Nkossa, Nsoko and Moho-Bilondo). The licenses for Nsoko, Nkossa and Moho-Bilondo expire in 2018, 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 2015 was 18,000 barrels of liquids.

Moho Nord The Moho Nord Project, located in the Moho-Bilondo development area, includes Albian reservoirs producing to a new facilities hub and Miocene reservoirs producing both to the new hub and through a subsea tieback to the existing Moho-Bilondo floating production unit (FPU). Development drilling commenced in 2015 and is planned to continue until 2020. Fabrication of the tension leg platform, FPU and subsea production systems continued during 2015, and enhancements are under way at existing facilities to accommodate the new production. First production to the existing Moho-Bilondo FPU commenced in December 2015, and total daily production is expected to reach 140,000 barrels of crude oil.

Exploration In 2015, the company conducted prospect identification activities. Drilling commenced on an exploration well in the Moho-Bilondo area in December 2015 and was completed in January 2016, and the results are under evaluation.

Liberia

Chevron operates and holds a 45 percent interest in three blocks off the coast of Liberia. The deepwater blocks, LB-11, LB-12 and LB-14, cover a combined area of 819,000 net acres (3,314 sq km).

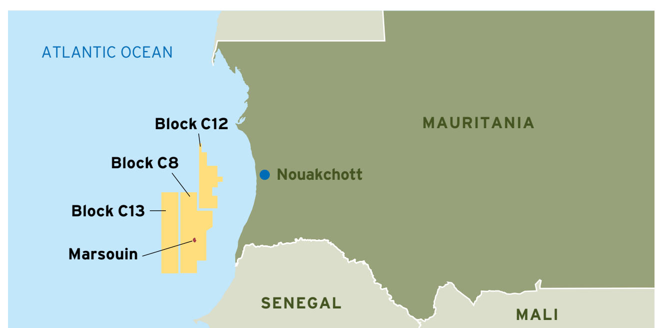
Chevron Interest

Sierra Leone

In third quarter 2015, Chevron relinquished two deepwater blocks, SL-8A-10 and SL-8B-10.

Mauritania

In early 2015, the company acquired a 30 percent nonoperated working interest in the C8, C12 and C13 contract areas offshore Mauritania. The blocks cover 2.0 million net acres (8,033 sq km) and have a water depth between 5,000 and 10,000 feet (1,600 m and 3,000 m). A deepwater exploration well was drilled to test the Marsouin prospect in Block C8 during 2015, resulting in a natural gas discovery. The company is evaluating whether to retain its working interest in the contract areas.



Chevron Interest Natural Gas Field

Morocco

The company operates and holds a 75 percent interest in three deepwater areas offshore Morocco. The areas, Cap Rhir Deep, Cap Cantin Deep and Cap Walidia Deep, encompass approximately 5.4 million net acres (21,913 sq km). The acquisition of Block Cap Rhir Deep 3-D seismic data was completed in 2015. In early 2016, Chevron reached an agreement to farm out a 30 percent interest in the three leases.

Chevron Interest

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 percent to 100 percent. In 2015, net daily production averaged 224,000 barrels of crude oil, 246 million cubic feet of natural gas and 6,000 barrels of liquefied petroleum gas (LPG). The company is pursuing selected opportunities for divestment and farm-down in Nigeria.

Chevron Interest
Swamp Areas
Crude Oil Field
Natural Gas Field
Terminal
West African Gas Pipeline

Niger Delta

In 2015, net daily production from 27 fields in the Niger Delta averaged 65,000 barrels of crude oil, 229 million cubic feet of natural gas and 6,000 barrels of LPG.

Deep Water

In 2015, net daily production from the deepwater Agbami and Usan fields averaged 159,000 barrels of crude oil and 17 million cubic feet of natural gas.

Agbami In 2015, net daily production from the Agbami Field averaged 129,000 barrels of crude oil and 14 million cubic feet of natural gas. The 67.3 percent-owned and operated field spans Oil Mining Lease (OML) 127 and OML 128. The 10-well second phase development program, Agbami 2, is expected to offset field decline. The last Agbami 2 well is expected on line in second quarter 2016. The third development phase, Agbami 3, is a five-well drilling program that is also expected to offset field decline. Drilling for this phase commenced in early 2015 and is scheduled to end in 2017. The first Agbami 3 development well commenced production in third quarter 2015. The leases that contain the Agbami Field expire in 2023 and 2024.

Usan Chevron holds a 30 percent nonoperated working interest in the Usan Field in OML 138. Net daily production in 2015 averaged 30,000 barrels of crude oil and 3 million cubic feet of natural gas. The PSC expires in 2023.

Bonga SW/Aparo 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, which is located 70 miles (113 km) off the coast of the western Niger Delta region in 4,300 feet (1,311 m) of water. The development plan involves subsea wells tied back to an FPSO, with a planned design capacity of 225,000 barrels of crude oil per day. Spending is being paced until market conditions and reductions in project costs are sufficient to support the development of this project. At the end of 2015, no proved reserves were recognized for this project.

Exploration Chevron operates and holds a 55 percent interest in OML 140, following completion of a farm-down in second quarter 2015. OML 140 includes the Nsiko discovery, which is 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 multiwell exploration program commenced in fourth quarter 2014 near the Nsiko discovery. Two wells were completed in 2015, both resulting in crude oil discoveries. A third exploration well was under way at year-end 2015 and is expected to be completed in March 2016. Additional exploration activities are planned for 2016. Chevron holds a 30 percent nonoperated working interest in OML 138, which includes the Usan Field. In 2015, an exploration well was drilled in the Usan area that resulted in a crude oil discovery. In 2016, the company plans to evaluate development options for the 2014 and 2015 discoveries in the Usan area.

Natural Gas Commercialization

Chevron's natural gas commercialization efforts in the Escravos area are expected to monetize total potentially recoverable natural gas resources of approximately 18 trillion cubic feet through a combination of domestic and export sales, power generation, and use as fuel in company operations. Major commercialization projects include the continued optimization of the Escravos Gas Plant (EGP), the Escravos Gas-to-Liquids (EGTL) facility and the Sonam Field Development Project.

EGP Phase 3B Chevron operates and holds a 40 percent interest in the EGP. Phase 3B is focused on eliminating routine flaring of natural gas that is associated with the production of crude oil. The project includes a 120 million-cubic-foot-per-day natural gas gathering and compression platform near the existing Meren 1 complex, 74 miles (119 km) of subsea pipelines, and modifications to nine existing production platforms in eight near-shore fields. Hook-up and commissioning of the topsides of the Meren gas gathering and compression platform was completed and project start-up was achieved in June 2015.

EGTL Chevron is the operator of the 33,000-barrel-per-day gas-to-liquids facility. The facility is designed to process 325 million cubic feet per day of natural gas from the EGP.

Sonam Field Development The 40 percent-owned and operated Sonam natural gas field is located in OML 91. The Sonam Field Development Project is designed to process natural gas through the EGP facilities, to deliver a total of 215 million cubic feet of natural gas per day to the domestic gas market and to produce a total of 30,000 barrels of liquids per day. Construction of offshore facilities continued in 2015. First production is expected in 2017. Proved reserves have been recognized for this project.

Photo: Construction at the Sonam facilities continued during 2015.

West African Gas Pipeline With a 36.7 percent interest, Chevron is the largest shareholder in West African Gas Pipeline Company Limited, which owns and operates the 421-mile (678-km) West African Gas Pipeline. The pipeline supplies Nigerian natural gas to customers in Benin, Ghana and Togo for industrial applications and power generation and has the capacity to transport 170 million cubic feet of natural gas per day.

South Africa

In 2015, the company discontinued evaluating shale gas exploration opportunities in the Karoo Basin in South Africa.

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. Net daily oil-equivalent production of 1,089,000 barrels during 2015 in these countries represented 41 percent of the companywide total.

Azerbaijan

Chevron holds an 11.3 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 2024. 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 2015, average net daily production was 32,000 barrels of crude oil and 12 million cubic feet of natural gas. Production associated with the Chirag Oil Project ramped up in 2015, and drilling activities continue. 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 has a capacity to transport 100,000 barrels per day.

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 2015 from TCO and Karachaganak was 311,000 barrels of liquids and 486 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 2015 averaged 257,000 barrels of crude oil, 348 million cubic feet of natural gas and 21,000 barrels of NGLs. The majority of TCO's crude oil production was exported through the Caspian Pipeline Consortium (CPC) Pipeline. The balance of production was exported by rail to Black Sea ports and via the BTC Pipeline to the Mediterranean.

In 2015, work progressed on three projects. The Capacity and Reliability (CAR) Project is designed to reduce facility bottlenecks and increase plant capacity and reliability. Fabrication activities for the CAR Project progressed during 2015. The Wellhead Pressure Management Project (WPMP) is designed to maintain production capacity and extend the production plateau from existing assets. The Future Growth Project (FGP) is designed to increase total daily production by 250,000 to 300,000 barrels of liquids and to increase the ultimate recovery from the reservoir. The FGP is planned to expand the utilization of sour gas injection technology proven in existing operations. The final investment decisions for the FGP and the WPMP are expected in mid-2016 following final alignment with partners on project costs and financing. Proved reserves have been recognized for the WPMP and the CAR Project.

Karachaganak The Karachaganak Field is located in northwest Kazakhstan, and operations are conducted under a PSC that expires in 2038. The development of the field is being conducted in phases. Net daily production during 2015 averaged 33,000 barrels of liquids and 138 million cubic feet of natural gas, including 32,000 net barrels per day of processed liquids, which were exported and sold at prices available in world markets. Most of the exported liquids were transported through the CPC Pipeline. A portion was also exported via the Atyrau-Samara (Russia) Pipeline. Liquids not exported by these pipelines were sold as condensate into the local and Russian markets. Work continues on identifying the optimal scope for the future expansion of the field. At the end of 2015, proved reserves had not been recognized for a 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 2015, the CPC Pipeline transported an average of 927,000 barrels of crude oil per day to Novorossiysk, composed of 824,000 barrels per day from Kazakhstan and 103,000 barrels per day from Russia.

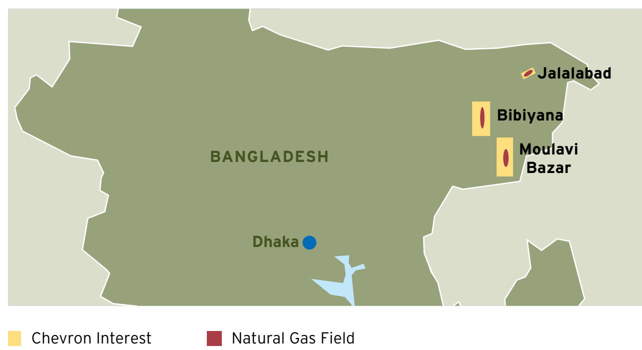
In 2015, work continued on the expansion of the pipeline, with capacity brought on incrementally as critical components of the project were completed. By mid-2015, capacity from Kazakhstan was increased to 925,000 barrels per day, allowing 100 percent of TCO's production to be exported via the CPC Pipeline. Additional capacity is scheduled to be added through the end of 2016, reaching a design capacity of 1.4 million barrels per day. The expansion is expected to provide additional transportation capacity that accommodates a portion of the future growth in TCO production.

Photo: CPC expansion activities progressed at the tanker-loading terminal in Novorossiysk, Russia.

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 2024, from Moulavi Bazar in 2028 and from Bibiyana in 2034.

The company sells the natural gas production to the government under long-term sales agreements. In 2015, net daily production averaged 720 million cubic feet of natural gas and 3,000 barrels of condensate.



Bibiyana The Bibiyana Expansion Project includes two gas processing trains, additional development wells and an enhanced liquids recovery facility and has an incremental design capacity of 300 million cubic feet of natural gas and 4,000 barrels of condensate per day. Start-up of the liquid recovery facility was achieved in first quarter 2015. The expected economic life of the project is the duration of the PSC.

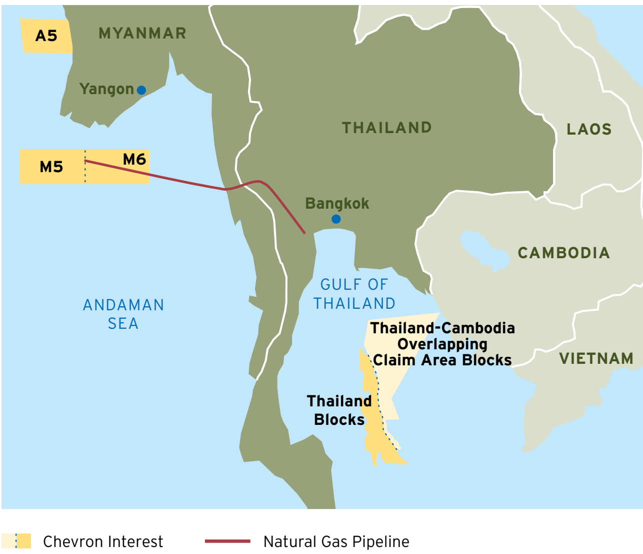
Activities continued on the Bibiyana Compression Project during 2015. The project is expected to provide incremental production to offset field decline. A final investment decision is pending commercial negotiations. At the end of 2015, proved reserves had not been recognized for this project.

Myanmar

Chevron has a 28.3 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana and Sein fields, within Blocks M5 and M6, in the Andaman Sea. The PSC expires in 2028. The company also has a 28.3 percent nonoperated interest in a pipeline company that transports most of the 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 2015 averaged 117 million cubic feet.

The Badamyar-Low Compression Platform (LCP) is an expansion project in Block M5 to maintain the existing production plateau. The Badamyar-LCP is designed to maintain production from the Yadana Field by lowering wellhead pressure and includes a compression platform, a remote wellhead platform and four development wells in the Badamyar Field. Fabrication activities progressed during 2015, and first production is expected in 2017. Proved reserves have been recognized for this project.

In second quarter 2015, Chevron signed a PSC to explore for oil and gas in Block A5, which covers 2.6 million net acres (10,500 sq km). The company holds a 99 percent interest in and operates this block. A 3-D seismic survey was completed in December 2015.



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 percent to 80 percent. Concessions for the producing areas in the Pattani Basin expire between 2020 and 2035. In the Malay Basin, Chevron holds a 16 percent nonoperated 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 2015 was 66,000 barrels of crude oil and condensate and 1.0 billion cubic feet of natural gas.

Ubon The development concept of the 35 percent-owned and operated Ubon Project includes facilities and wells to develop resources in Block 12/27. The company continues to assess alternatives for the optimum development of the Ubon Field. At the end of 2015, proved reserves had not been recognized for this project.

Exploration In 2015, the company drilled three exploration and three delineation wells in the operated areas of the Pattani Basin, and all wells were successful. In addition, at the Arthit Field, two successful exploration wells were drilled.

Chevron also holds operated and nonoperated working interests in the Thailand-Cambodia overlapping claims area that range from 30 percent to 80 percent. As of year-end 2015, these areas were inactive pending resolution of border issues between Thailand and Cambodia.

Vietnam

In June 2015, Chevron completed the sale of its entire interest in Vietnam, which included a 42.4 percent working interest in Blocks B and 48/95, a 43.4 percent working interest in Block 52/97, and a 28.7 percent nonoperated interest in a pipeline project.

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, which contains the BZ 19-4 and BZ 25-1 crude oil fields. The company holds a 24.5 percent working interest in the Qinhuangdao (QHD) 32-6 Block, which contains the QHD 32-6 crude oil field. The PSCs for these producing assets expire between 2022 and 2028.

In 2015, net average daily production was 24,000 barrels of crude oil.

Chuandongbei The first stage of the project's development includes the Xuanhan Gas Plant's initial three gas processing trains with a design outlet capacity of 258 million cubic feet per day. Production commenced from the Xuanhan Plant in January 2016 with gas supplied from the Luojiazhai natural gas field. The company continues to assess alternatives for the optimum development of the remaining Chuandongbei natural gas area. This project is estimated to contain total potentially recoverable natural gas resources of 3 trillion cubic feet. The PSC expires in 2038.

Photo: First production from the Chuandongbei natural gas project in the Sichuan Basin was achieved in January 2016.

Exploration The company completed one exploration well in Block 15/10 in the South China Sea in May 2015. The results were unsuccessful, and the block was relinquished in September 2015. The company also relinquished Block 15/28 in September 2015.

Chevron Interest   Natural Gas Field   Crude Oil Field
Geothermal Field   Terminal

Philippines

Malampaya Chevron holds a 45 percent nonoperated working interest in the Malampaya Field, offshore Palawan. Located in 2,800 feet (853 m) of water, the Malampaya development includes an offshore platform, seven production wells and a 314-mile (505-km) pipeline from the platform to the Batangas onshore natural gas plant. Net daily production during 2015 averaged 122 million cubic feet of natural gas and 3,000 barrels of condensate. The Malampaya Phase 2 Project was completed in September 2015. The infill wells and compression facilities have maintained production and delivered contracted volumes to customers.

Geothermal Chevron has a 40 percent equity interest in the Philippine Geothermal Production Company, Inc. (PGPC). The PGPC develops and produces steam resources for the third-party Tiwi and Mak-Ban geothermal power plants in southern Luzon, which have a combined operating capacity of 692 megawatts. The renewable energy service contract with the Philippine government expires in 2038.

Chevron also has an interest in the Kalinga geothermal prospect area in northern Luzon.

Indonesia

Chevron's operated interests in Indonesia include one onshore PSC on the island of Sumatra and four PSCs offshore eastern Kalimantan. In addition, the company operates two geothermal fields in West Java. Chevron also holds a nonoperated working interest in the offshore South Natuna Sea Block B, located northeast of the island of Sumatra. Net daily production in 2015 from all producing areas in Indonesia averaged 176,000 barrels of liquids and 185 million cubic feet of natural gas.

Chevron Interest   Geothermal Field

Sumatra

Chevron holds a 100 percent-owned and operated interest in the Rokan PSC, which expires in 2021. Net daily production averaged 154,000 barrels of crude oil and 31 million cubic feet of natural gas in 2015.

Duri is the largest producing field in the Rokan PSC. Duri has been under steamflood since 1985 and is one of the world's largest steamflood developments. In 2015, 77 percent of the field was under steam injection, with net daily production averaging 72,000 barrels of crude oil. Infill drilling and workover programs continued in 2015. The Duri Field Area 13 steamflood expansion was completed in 2015 with all wells on production and injection by year-end.

The remaining production from the Rokan PSC is in the Sumatra light oil area, consisting of 76 active fields with net daily production that averaged 82,000 barrels of crude oil and 31 million cubic feet of natural gas in 2015. Production was underpinned by robust infill drilling results across the area. Activity continued on the Minas Field chemical injection pilot in 2015.

Kutei Basin

Chevron's operated interests offshore eastern Kalimantan includes four PSCs in the Kutei Basin: East Kalimantan (92.5 percent), Makassar Strait (72 percent), Rapak (62 percent) and Ganal (62 percent). The PSCs for East Kalimantan, Makassar Strait, Rapak and Ganal expire in 2018, 2020, 2027 and 2028, respectively. Net daily production averaged 17,000 barrels of crude oil and 88 million cubic feet of natural gas in 2015. The majority of the production came from 14 fields in the shelf area within the East Kalimantan PSC, with the remainder from the deepwater West Seno Field in the Makassar Strait PSC. In 2016, Chevron advised the government of Indonesia that it would not propose to extend the East Kalimantan PSC and intends to return the assets to the government upon PSC expiration in 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.

One of these projects, Bangka, includes a subsea tieback to the West Seno FPU, with a design capacity of 115 million cubic feet of natural gas and 4,000 barrels of condensate per day. The company's interest is 62 percent. Installation of subsea facilities and completion of the two development wells continues to progress, with first gas planned for second-half 2016. Proved reserves have been recognized for this project.

The other project, Gendalo-Gehem, includes two separate hub developments, each with its own FPU, subsea drill centers, natural gas and condensate pipelines, and onshore receiving facility. Gas from the project is expected to be sold domestically and through LNG export. Liquefaction is planned to take place at the state-owned Bontang LNG plant in East Kalimantan. The project has a planned design capacity of 1.1 billion cubic feet of natural gas and 47,000 barrels of condensate per day. The company's interest is approximately 63 percent. Chevron continues to work toward a final investment decision, subject to the timing of government approvals, including extension of the associated PSCs, and securing new LNG sales contracts. This project is estimated to contain total potentially recoverable natural gas resources of approximately 3 trillion cubic feet. At the end of 2015, proved reserves had not been recognized for this project.

South Natuna Sea Block B

Chevron holds a 25 percent nonoperated working interest in the offshore South Natuna Sea Block B. Net daily production during 2015 from eight fields averaged 5,000 barrels of liquids and 66 million cubic feet of natural gas.

Geothermal

The company operates the Darajat geothermal field and holds a 95 percent interest in two power plants in West Java. The field supplies steam to a three-unit power plant with a total operating capacity of 270 megawatts.

Chevron also operates and holds a 100 percent interest in the Salak geothermal field in the Gunung Salak contract area in West Java. The field supplies steam to a six-unit power plant, three of which are company owned, with a total operating capacity of 377 megawatts.

In 2014, Chevron secured the preliminary survey assignment for a South Sekincau prospect. In June 2015, Chevron submitted preliminary survey results to the government of Indonesia.

Kurdistan Region of Iraq

The company operates and holds an 80 percent contractor interest in the Sarta PSC and the Qara Dagh PSC. The two blocks cover a combined area of 279,000 net acres (1,129 sq km).

In first quarter 2015, the company resumed operations and the testing and evaluation programs at the Rovi and Sarta wells and restarted the seismic data acquisition program at the Qara Dagh Block, which was completed in the second quarter. The company drilled a second exploration well in the Sarta Block in second-half 2015, and as of early 2016, the results are under evaluation. The Rovi Block was relinquished in fourth quarter 2015.

Partitioned Zone

Chevron holds a concession agreement to operate the Kingdom of Saudi Arabia's 50 percent interest in the hydrocarbon resources of 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.

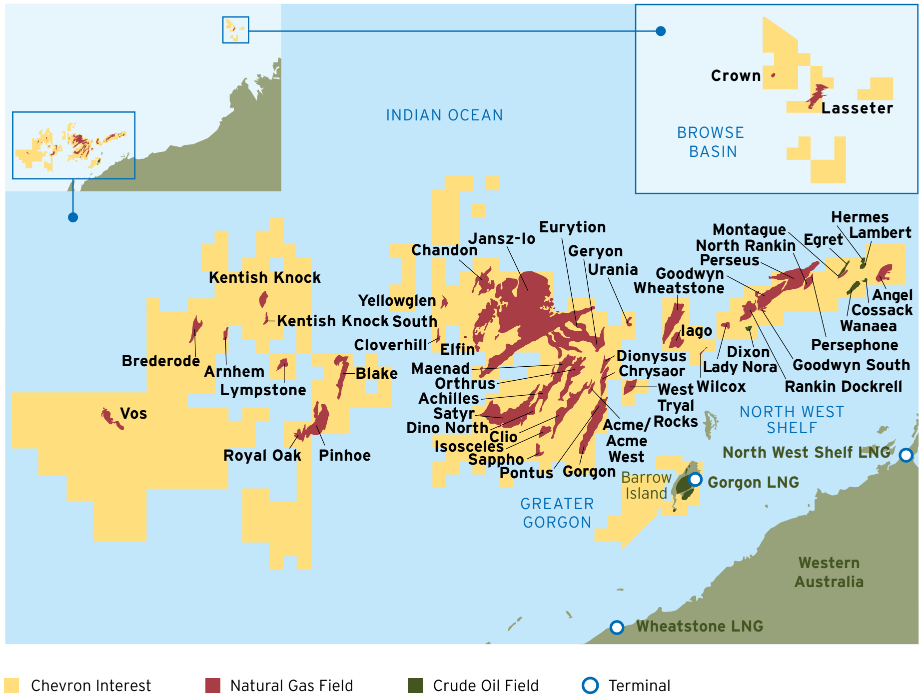
During 2015, net daily production from four fields averaged 27,000 barrels of crude oil and 5 million cubic feet of natural gas. Beginning in May, production in the Partitioned Zone was shut in as a result of continued difficulties in securing work and equipment permits. As of early 2016, production remains shut in and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait. Once production resumes, additional development drilling, well workovers and numerous facility-enhancement programs are expected to partially offset field declines.

The shut-in also impacted plans for both the Wafra Steamflood Stage 1 Project, a full-field steamflood application in the Wafra Field First Eocene carbonate reservoir with a planned design capacity of 100,000 barrels of crude oil per day, and the Central Gas Utilization Project, a facility construction project intended to increase natural gas utilization while eliminating natural gas flaring at the Wafra Field. Both projects have been deferred pending dispute resolution between Saudi Arabia and Kuwait. At the end of 2015, proved reserves had not been recognized for these two projects.

Exploration In 2015, the company continued to progress a 3-D seismic survey covering the entire onshore Partitioned Zone. It is one of the largest land seismic programs ever undertaken, covering 1.1 million acres (4,600 sq km).

Australia/Oceania

In Australia/Oceania, the company is engaged in upstream activities in Australia and New Zealand. Net daily oil-equivalent production of 94,000 barrels during 2015 in Australia represented 4 percent of the companywide total.



Australia

Chevron is the largest holder of natural gas resources in Australia and the operator of two major LNG projects, Gorgon and Wheatstone, where total potentially recoverable natural gas from the fields that are planned to supply these projects is estimated at more than 50 trillion cubic feet. Chevron also has a nonoperated working interest in the North West Shelf (NWS) Venture, as well as exploration acreage in the Carnarvon Basin, Browse Basin and Bight Basin. Net daily production in 2015 averaged 21,000 barrels of liquids and 439 million cubic feet of natural gas.

Gorgon Chevron holds a 47.3 percent interest in and is the operator of the Gorgon Project, which includes the development of the Gorgon and Jansz-Io fields. The project includes a three-train, 15.6 million-metric-ton-per-year LNG facility, a carbon dioxide injection facility and a domestic gas plant with capacity to supply 280 million cubic feet per day to the Western Australian market. The facilities are located on Barrow Island. The offshore portion of the development includes subsea infrastructure and pipelines. The total production capacity for the project is approximately 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate per day. The project's estimated economic life exceeds 40 years.

Photo: The cool-down of the LNG export system commenced in January 2016, following the arrival of an LNG commissioning cargo.

Pre-commissioning and commissioning activities progressed during 2015 on LNG Train 1, the utility systems, the LNG and condensate tanks, the loading jetty infrastructure, and the pipelines. All Train 2 modules have been installed at Barrow Island, and all Train 3 modules were delivered as of January 2016. LNG Train 1 start-up was achieved, with first cargo lifting expected in March 2016. Trains 2 and 3 are expected to start up sequentially at approximately six-month intervals after LNG Train 1.

Wheatstone Chevron is the operator of the Wheatstone Project, which includes a two-train, 8.9 million-metric-ton-per-year LNG facility and a 190 million-cubic-feet-per-day domestic gas plant, both located at Ashburton North, on the coast of Western Australia. The company plans to supply natural gas to the facilities from the Wheatstone and Iago fields. Chevron holds an 80.2 percent interest in the offshore licenses and a 64.1 percent interest in the LNG facilities. 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. Start-up of the first LNG train is targeted for mid-2017. Proved reserves have been recognized, and the project's estimated economic life exceeds 30 years from the time of start-up.

Photo: Steady progress continues at the Wheatstone Project.

Construction and fabrication continue to progress. Key milestones achieved during 2015 include the completion of five of nine production wells; the installation of 330 km of subsea flowlines and pipelines, including setting all 13 subsea structures; setting the offshore platform topsides; and commencing hook-up and commissioning. Dredging, construction of plant operations center, mobilization of permanent operations and maintenance personnel to site, and delivery of all LNG Train 1 and common area modules required for plant start-up were completed in 2015. Key activities for 2016 include structural, piping, mechanical and instrument electrical works at the plant, systems commissioning and completion of the remaining production wells.

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. The NWS Venture concession expires in 2034.

Net daily production in 2015 averaged 15,000 barrels of crude oil and condensate, 439 million cubic feet of natural gas, and 3,000 barrels of LPG.

The NWS Venture continues to progress additional natural gas supply opportunities to maintain NWS production through development of the remaining fields in the permit area, which includes a program of subsea tiebacks to the existing offshore infrastructure. The Greater Western Flank-1 Development Project achieved first production in October 2015. Construction commenced on the Eastern Flank Persephone Project in June 2015, and first production is expected in 2018. The Greater Western Flank-2 Development Project reached a final investment decision in December 2015, with first production expected in 2019. The initial recognition of proved reserves occurred in 2015 for this project.

Gas Commercialization Approximately 85 percent of the equity LNG offtake from the Gorgon and Wheatstone projects is targeted to be sold into binding long-term contracts, with the remainder to be sold in the Asian spot LNG market. In December 2015, Chevron signed a nonbinding Heads of Agreement (HOA) for delivery of up to 1 million metric tons per annum (MTPA) of LNG over 10 years starting in 2020. In early 2016, the company announced the signing of a nonbinding HOA for the delivery of up to 0.5 million MTPA of LNG over 10 years, with deliveries starting in 2018 or 2019. Assuming these HOAs are converted to binding sales agreements, more than 80 percent of Chevron's equity LNG offtake from these projects would be covered under binding agreements during the time of these agreements. Chevron also has binding, long-term agreements for delivery of natural gas to customers in Western Australia and continues to market additional pipeline natural gas quantities from the project.

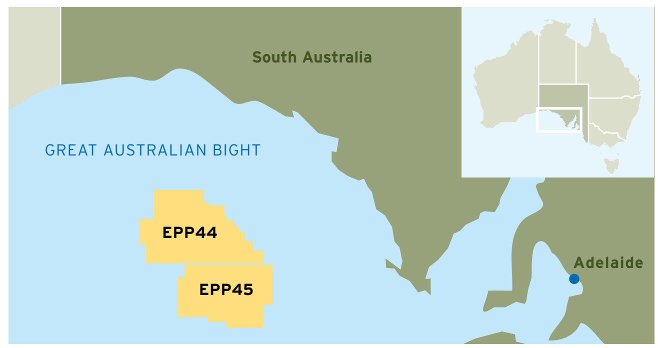
In the NWS Venture, approximately 70 percent of Chevron's equity LNG offtake is committed under binding, long-term sales agreements with major utilities in Asia. Chevron also sells natural gas to the domestic market in Western Australia.

Barrow Island Chevron operates and holds a 57.1 percent working interest in crude oil production operations at Barrow Island. In 2015, net daily production averaged 3,000 barrels of crude oil.

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

Carnarvon Basin Exploration During 2015, Chevron made one natural gas discovery in the Carnarvon Basin. This discovery at the Isosceles prospect contributes to the resources available to extend and expand Chevron's LNG projects in the region.

Great Australian Bight Exploration The company operates and holds a 100 percent interest in offshore Blocks EPP44 and EPP45, which span 8.0 million net acres (32,375 sq km) in the Bight Basin off the South Australian coast. In 2015, the company completed its second 3-D seismic survey in this area. Processing and interpretation of the seismic data is planned to continue through 2016.



Chevron Interest

Nappamerri Trough In March 2015, the company withdrew from its interest in the Permian section of petroleum retention license (PRL) 33-49 in South Australia and authority to prospect (ATP) 855 in Queensland.

New Zealand

Effective April 2015, Chevron became operator of three exploration permits, 57083, 57085 and 57087, in the offshore Pegasus and East Coast basins. The company holds a 50 percent interest in the deepwater permits, which cover 3.2 million net acres (13,014 sq km) and are located approximately 100 miles (161 km) east of Wellington. Acquisition of 2-D and 3-D seismic data is scheduled to commence in late 2016.

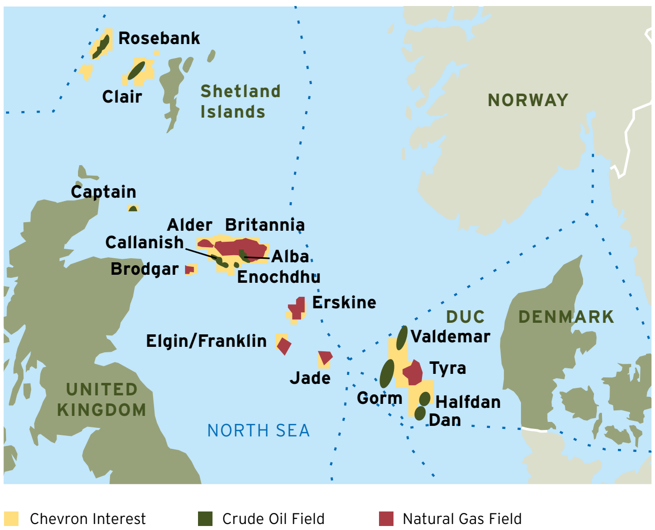
Chevron Interest

Europe

In Europe, the company is engaged in upstream activities in Denmark and the United Kingdom. Net daily oil-equivalent production of 83,000 barrels during 2015 in this region represented approximately 3 percent of the companywide total.

Denmark

Chevron holds a 12 percent nonoperated working interest in the Danish Underground Consortium (DUC). The DUC has production from 13 North Sea fields, with the majority of crude oil production from the Halfdan, Dan and Valdemar fields and the majority of natural gas production from the Tyra Field. Average net daily production in 2015 from the DUC was 16,000 barrels of crude oil and 50 million cubic feet of natural gas. The concession expires in 2042.



Norway

Chevron relinquished its interest in the PL 527 and PL 598 exploration licenses in May 2015.

Poland

In 2015, Chevron relinquished its remaining exploration licenses.

Romania

The company relinquished the Barlad concession in northeast Romania, and as of early 2016, the relinquishment is pending government approval. In addition, the company is pursuing relinquishment of its remaining concessions in southeast Romania.

United Kingdom

Chevron has working interests in 10 offshore producing fields, including three operated fields (Alba, 23.4 percent; Captain, 85 percent; and Erskine, 50 percent) and seven nonoperated fields (Britannia, 32.4 percent; Brodgar, 25 percent; Callanish, 16.5 percent; Clair, 19.4 percent; Elgin/Franklin, 3.9 percent; Enochdhu, 50 percent; and Jade, 19.9 percent). Net daily production in 2015 from the fields averaged 40,000 barrels of liquids and 115 million cubic feet of natural gas.

Alder The 73.7 percent-owned and operated Alder high-pressure, high-temperature gas condensate discovery is located 17 miles (27 km) west of the Britannia Field in the North Sea. The field is being developed via a single subsea well tied back to existing Britannia facilities. Installation of the flowline was completed in first quarter 2015, and installation of topsides was completed mid-year. Drilling of the development well commenced in third quarter 2015. First production is expected in second-half 2016. The project has a design capacity of 14,000 barrels of condensate and 110 million cubic feet of natural gas per day. Proved reserves have been recognized for this project.

Photo: Installation of platform topsides for the Alder Project was completed in mid-2015.

Captain EOR The Captain EOR Project is the next development phase of the Captain Field and is designed to increase field recovery by injecting polymerized water into the Captain reservoir. FEED activities continued to progress in 2015 and are planned to continue in 2016 as polymer performance is evaluated. At the end of 2015, proved reserves had not been recognized for this project.

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. Fabrication and installation activities continued during 2015. The design capacity of the project is 120,000 barrels of crude oil and 100 million cubic feet of natural gas per day. Production is expected to begin in 2017. The project is estimated to provide incremental potentially recoverable oil-equivalent resources in excess of 600 million barrels. Proved reserves have been recognized for the Clair Ridge Project. The Clair Field has an estimated production life until 2050.

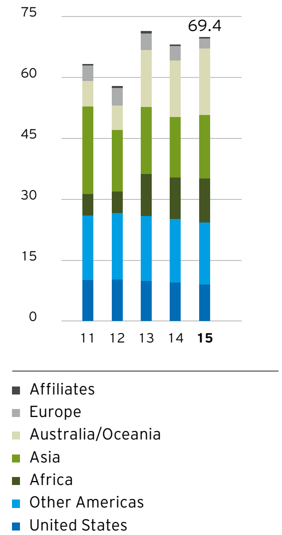
Rosebank The Rosebank Field is 80 miles (129 km) northwest of the Shetland Islands in 3,700 feet (1,115 m) of water. Chevron operates and holds a 40 percent interest in the project. FEED activities continued to progress in 2015 and are planned to continue in 2016. The selected design is a 17-well subsea development tied back to an FPSO, with natural gas exported via pipeline. The design capacity of the project is 100,000 barrels of crude oil and 80 million cubic feet of natural gas per day. At the end of 2015, proved reserves had not been recognized for this project.

Oil and Gas Acreage[1,2]

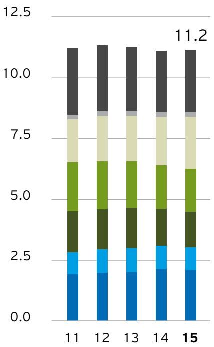
Thousands of acres	Gross Acres 2015	Net Acres 2015	2014	2013	2012	2011
		At December 31				
Consolidated Companies						
Total United States	**12,337**	**8,885**	9,444	9,839	10,169	10,058
Other Americas						
Argentina	**388**	**240**	240	216	167	167
Brazil	**256**	**104**	105	105	64	64
Canada	**22,826**	**12,913**	13,204	13,485	14,403	14,050
Colombia	**203**	**87**	87	87	87	87
Greenland	**1,199**	**350**	350	350	–	1,006
Suriname	**2,793**	**1,396**	1,396	1,396	1,400	-
Trinidad and Tobago	**168**	**84**	84	84	84	84
Venezuela	**74**	**58**	58	58	58	275
Total Other Americas	**27,907**	**15,232**	15,524	15,781	16,263	15,733
Africa						
Angola	**2,350**	**802**	802	803	807	875
Chad	**–**	**–**	–	28	28	28
Democratic Republic of the Congo	**249**	**44**	44	44	44	44
Liberia	**1,820**	**819**	819	819	903	1,661
Mauritania	**6,616**	**1,985**	–	–	–	–
Morocco	**7,220**	**5,415**	5,415	5,415	–	–
Nigeria	**3,581**	**1,552**	2,194	2,443	2,620	2,634
Republic of Congo	**213**	**56**	63	43	49	49
Sierra Leone	**–**	**–**	762	762	762	–
Total Africa	**22,049**	**10,673**	10,099	10,357	5,213	5,291
Asia						
Azerbaijan	**111**	**12**	12	12	12	12
Bangladesh	**186**	**186**	186	184	182	182
Cambodia	**–**	**–**	–	349	349	349
China	**353**	**134**	1,565	2,143	921	4,396
Indonesia	**9,547**	**5,853**	5,853	6,468	6,536	6,536
Kazakhstan	**67**	**12**	12	14	14	16
Kurdistan Region of Iraq	**349**	**279**	355	355	185	–
Myanmar	**9,067**	**4,407**	1,826	1,826	1,826	1,826
Partitioned Zone	**1,361**	**681**	681	681	681	681
Philippines	**206**	**93**	93	93	93	93
Thailand	**9,536**	**3,797**	3,843	3,892	3,908	4,118
Turkey	**–**	**–**	–	–	–	2,781
Vietnam	**–**	**–**	339	339	339	339
Total Asia	**30,783**	**15,454**	14,765	16,356	15,046	21,329
Australia/Oceania						
Australia	**18,769**	**13,061**	13,875	13,891	5,967	6,304
New Zealand	**6,431**	**3,216**	–	–	–	–
Total Australia/Oceania	**25,200**	**16,277**	13,875	13,891	5,967	6,304
Europe						
Denmark	**406**	**49**	49	49	50	63
Netherlands	**–**	**–**	–	26	30	26
Norway	**–**	**–**	520	523	526	526
Poland	**–**	**–**	499	1,085	1,085	1,085
Romania	**2,239**	**2,239**	2,239	2,239	2,239	1,569
United Kingdom	**680**	**210**	210	196	349	476
Total Europe	**3,325**	**2,498**	3,517	4,118	4,279	3,745
Total Consolidated Companies	**121,601**	**69,019**	67,224	70,342	56,937	62,460
Equity Share in Affiliates						
Kazakhstan	**380**	**190**	190	190	190	190
Lithuania	**–**	**–**	–	197	197	–
Venezuela	**423**	**145**	145	145	145	145
Total Equity Share in Affiliates	**803**	**335**	335	532	532	335
Total Worldwide	**122,404**	**69,354**	67,559	70,874	57,469	62,795

[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

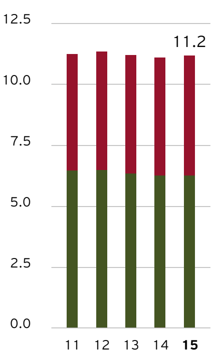


Net Proved Reserves
Billions of BOE*



*BOE (barrels of oil-equivalent)

Net Proved Reserves Liquids vs. Natural Gas
Billions of BOE



Net Proved Reserves – Liquids[1,2]

Millions of barrels	2015	2014	2013	2012	2011
					At December 31
Consolidated Companies					
United States	**1,386**	1,432	1,330	1,359	1,311
Other Americas	**833**	772	780	736	636
Africa	**957**	1,021	1,104	1,130	1,155
Asia	**790**	752	792	837	894
Australia/Oceania	**153**	142	131	134	140
Europe	**143**	166	166	157	159
Total Consolidated Companies	**4,262**	4,285	4,303	4,353	4,295
Equity Share in Affiliates					
TCO	**1,676**	1,615	1,668	1,732	1,759
Other	**324**	349	374	396	401
Total Equity Share in Affiliates	**2,000**	1,964	2,042	2,128	2,160
Total Worldwide	**6,262**	6,249	6,345	6,481	6,455

[1] Refer to page 50 for a definition of net proved reserves. For additional discussion of the company's proved reserves, refer to the company's *2015 Annual Report on Form 10-K*.
[2] Includes crude oil, condensate, NGLs and synthetic oil.

Net Proved Reserves – Natural Gas*

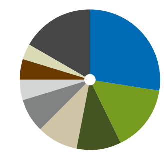
Billions of cubic feet	2015	2014	2013	2012	2011
					At December 31
Consolidated Companies					
United States	**4,242**	4,174	3,990	3,722	3,646
Other Americas	**714**	1,123	1,300	1,475	1,664
Africa	**2,937**	2,968	3,045	3,081	3,196
Asia	**5,956**	6,266	6,745	6,867	6,721
Australia/Oceania	**11,873**	10,941	10,327	10,252	9,744
Europe	**224**	235	263	257	258
Total Consolidated Companies	**25,946**	25,707	25,670	25,654	25,229
Equity Share in Affiliates					
TCO	**2,268**	2,177	2,290	2,299	2,251
Other	**1,223**	1,232	1,186	1,242	1,203
Total Equity Share in Affiliates	**3,491**	3,409	3,476	3,541	3,454
Total Worldwide	**29,437**	29,116	29,146	29,195	28,683

* Refer to page 50 for a definition of net proved reserves. For additional discussion of the company's proved reserves, refer to the company's *2015 Annual Report on Form 10-K*.

Net Oil-Equivalent Production

Thousands of barrels per day	Year ended December 31 2015	2014	2013	2012	2011
Consolidated Companies					
Total United States	**720**	664	657	655	678
Other Americas					
Argentina	**27**	25	19	22	27
Brazil	**18**	21	6	6	35
Canada	**69**	69	71	69	70
Colombia	**27**	31	36	36	39
Trinidad and Tobago	**19**	19	29	29	31
Total Other Americas	**160**	165	161	162	202
Africa					
Angola	**119**	121	127	137	147
Chad	**–**	8	19	23	26
Democratic Republic of the Congo	**3**	3	3	3	3
Nigeria	**270**	286	268	269	260
Republic of Congo	**20**	16	14	19	23
Total Africa	**412**	434	431	451	459
Asia					
Azerbaijan	**34**	28	28	28	28
Bangladesh	**123**	109	113	94	74
China	**24**	16	20	21	22
Indonesia	**207**	185	193	198	208
Kazakhstan	**56**	53	57	61	62
Myanmar	**20**	16	16	16	14
Partitioned Zone	**28**	81	87	90	91
Philippines	**23**	23	23	24	25
Thailand	**238**	238	229	243	209
Total Asia	**753**	749	766	775	733
Australia/Oceania					
Australia	**94**	97	96	99	101
Total Australia/Oceania	**94**	97	96	99	101
Europe					
Denmark	**24**	25	28	36	44
Netherlands	**–**	7	9	9	7
Norway	**–**	1	2	3	3
United Kingdom	**59**	47	55	66	85
Total Europe	**83**	80	94	114	139
Total Consolidated Companies	**2,222**	2,189	2,205	2,256	2,312
Equity Share in Affiliates					
TCO	**336**	314	321	286	296
Petropiar	**34**	34	36	37	35
Petroboscan	**28**	27	27	29	28
Petroindependiente	**2**	2	2	2	2
Angola LNG	**–**	5	6	–	–
Total Equity Share in Affiliates	**400**	382	392	354	361
Total Worldwide	**2,622**	2,571	2,597	2,610	2,673

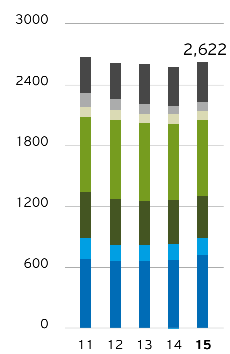
2015 Net Oil-Equivalent Production by Country*
Percentage



United States	27.5%
Kazakhstan	15.0%
Nigeria	10.3%
Thailand	9.1%
Indonesia	7.9%
Bangladesh	4.7%
Angola	4.5%
Australia	3.6%
Other	17.4%

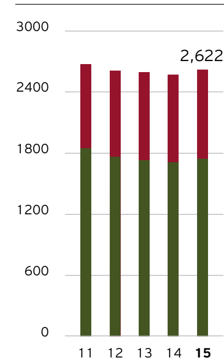
*Includes equity share in affiliates.

Net Oil-Equivalent Production
Thousands of barrels per day



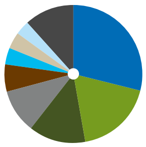
Affiliates
Europe
Australia/Oceania
Asia
Africa
Other Americas
United States

Net Production Liquids vs. Natural Gas
Thousands of barrels per day



Natural Gas
Liquids

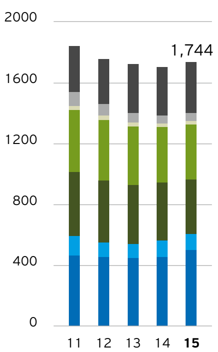
2015 Net Liquids Production by Country*
Percentage



United States	28.7%
Kazakhstan	17.8%
Nigeria	13.2%
Indonesia	10.1%
Angola	6.3%
Canada	3.8%
Thailand	3.8%
Venezuela	3.4%
Other	12.9%

*Includes equity share in affiliates.

Net Liquids Production
Thousands of barrels per day



Net Liquids Production

Thousands of barrels per day	2015	2014	2013	2012	2011
					Year ended December 31
Consolidated Companies					
Total United States	**501**	456	449	455	465
Other Americas					
Argentina	**21**	21	18	21	26
Brazil	**17**	20	5	6	33
Canada	**67**	67	70	68	69
Total Other Americas	**105**	108	93	95	128
Africa					
Angola	**110**	113	118	128	139
Chad	**–**	8	18	22	25
Democratic Republic of the Congo	**2**	2	2	2	3
Nigeria	**230**	246	238	242	236
Republic of Congo	**18**	14	13	17	21
Total Africa	**360**	383	389	411	424
Asia					
Azerbaijan	**32**	26	26	26	26
Bangladesh	**3**	2	2	2	2
China	**24**	16	19	20	20
Indonesia	**176**	149	156	158	166
Kazakhstan	**34**	31	34	37	38
Partitioned Zone	**27**	78	84	86	88
Philippines	**3**	3	3	4	4
Thailand	**66**	63	62	67	65
Total Asia	**365**	368	386	400	409
Australia/Oceania					
Australia	**21**	23	26	28	26
Total Australia/Oceania	**21**	23	26	28	26
Europe					
Denmark	**16**	17	19	24	29
Netherlands	**–**	2	2	2	2
Norway	**–**	1	2	3	3
United Kingdom	**40**	32	40	46	59
Total Europe	**56**	52	63	75	93
Total Consolidated Companies	**1,408**	1,390	1,406	1,464	1,545
Equity Share in Affiliates					
TCO	**277**	259	263	236	244
Petropiar	**31**	32	34	35	32
Petroboscan	**27**	26	26	28	27
Petroindependiente	**1**	1	1	1	1
Angola LNG	**–**	1	1	–	–
Total Equity Share in Affiliates	**336**	319	325	300	304
Total Worldwide	**1,744**	1,709	1,731	1,764	1,849

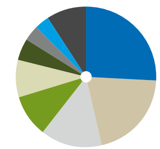
Net Natural Gas Production*

Millions of cubic feet per day	2015	2014	2013	2012	2011
					Year ended December 31
Consolidated Companies					
Total United States	**1,310**	1,250	1,246	1,203	1,279
Other Americas					
Argentina	**36**	23	6	4	4
Brazil	**5**	6	2	2	13
Canada	**14**	10	9	4	4
Colombia	**161**	186	216	216	234
Trinidad and Tobago	**116**	112	173	173	183
Total Other Americas	**332**	337	406	399	438
Africa					
Angola	**52**	51	52	53	50
Chad	**–**	2	4	6	6
Democratic Republic of the Congo	**1**	1	1	1	1
Nigeria	**246**	236	182	165	142
Republic of Congo	**11**	11	10	13	10
Total Africa	**310**	301	249	238	209
Asia					
Azerbaijan	**12**	12	10	10	10
Bangladesh	**720**	643	663	550	434
China	**–**	–	6	9	10
Indonesia	**185**	214	225	236	253
Kazakhstan	**138**	126	135	139	144
Myanmar	**117**	99	96	94	86
Partitioned Zone	**5**	18	19	21	20
Philippines	**122**	118	119	120	126
Thailand	**1,033**	1,046	1,003	1,060	867
Total Asia	**2,332**	2,276	2,276	2,239	1,950
Australia/Oceania					
Australia	**439**	442	421	428	448
Total Australia/Oceania	**439**	442	421	428	448
Europe					
Denmark	**50**	51	55	74	91
Netherlands	**–**	34	41	42	31
Norway	**–**	–	1	1	1
United Kingdom	**115**	88	94	122	155
Total Europe	**165**	173	191	239	278
Total Consolidated Companies	**4,888**	4,779	4,789	4,746	4,602
Equity Share in Affiliates					
TCO	**348**	334	347	301	312
Petropiar	**18**	15	13	14	13
Petroboscan	**5**	5	6	5	6
Petroindependiente	**7**	7	7	8	8
Angola LNG	**3**	27	30	–	–
Total Equity Share in Affiliates	**381**	388	403	328	339
Total Worldwide	**5,269**	5,167	5,192	5,074	4,941

* Includes natural gas consumed in operations:

United States	**66**	71	72	65	69
International	**430**	452	458	457	447
Total	**496**	523	530	522	516

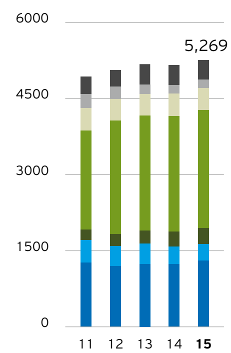
2015 Net Natural Gas Production by Country*
Percentage



United States	24.9%
Thailand	19.6%
Bangladesh	13.7%
Kazakhstan	9.2%
Australia	8.3%
Nigeria	4.7%
Indonesia	3.5%
Colombia	3.1%
Other	13.0%

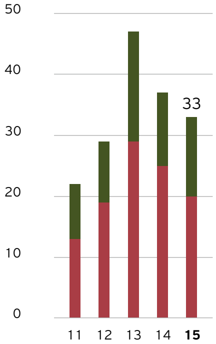
*Includes equity share in affiliates.

Net Natural Gas Production
Millions of cubic feet per day



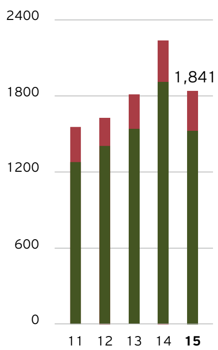
- Affiliates
- Europe
- Australia/Oceania
- Asia
- Africa
- Other Americas
- United States

Net Productive Exploratory Wells Completed
Number of wells



■ Crude Oil
■ Natural Gas

Net Productive Development Wells Completed
Number of wells



■ Natural Gas
■ Crude Oil

Net Wells Completed*

Year ended December 31

	2015		2014		2013		2012		2011	
	Productive	**Dry**	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
Consolidated Companies										
United States										
Exploratory	**16**	**4**	20	12	17	2	4	–	5	1
Development	**873**	**3**	1,085	8	1,101	4	941	6	909	9
Total United States	**889**	**7**	1,105	20	1,118	6	945	6	914	10
Other Americas										
Exploratory	**5**	**1**	3	–	12	2	8	–	1	–
Development	**99**	**–**	81	–	127	–	50	–	37	–
Total Other Americas	**104**	**1**	84	–	139	2	58	–	38	–
Africa										
Exploratory	**3**	**–**	1	2	–	–	1	2	1	–
Development	**9**	**–**	9	–	20	1	23	–	29	–
Total Africa	**12**	**–**	10	2	20	1	24	2	30	–
Asia										
Exploratory	**5**	**1**	7	2	13	4	12	3	10	1
Development	**828**	**5**	1,025	4	535	5	566	6	549	6
Total Asia	**833**	**6**	1,032	6	548	9	578	9	559	7
Australia/Oceania										
Exploratory	**1**	**4**	3	–	3	–	3	–	4	1
Development	**4**	**–**	9	–	–	–	–	–	–	–
Total Australia/Oceania	**5**	**4**	12	–	3	–	3	–	4	1
Europe										
Exploratory	**3**	**–**	3	–	2	2	1	2	–	1
Development	**2**	**–**	2	–	3	–	9	–	6	–
Total Europe	**5**	**–**	5	–	5	2	10	2	6	1
Total Consolidated Companies	**1,848**	**18**	2,248	28	1,833	20	1,618	19	1,551	19
Equity Share in Affiliates										
Exploratory	**–**	**–**	–	–	–	–	–	–	1	–
Development	**26**	**–**	25	1	25	–	26	–	25	–
Total Equity Share in Affiliates	**26**	**–**	25	1	25	–	26	–	26	–
Total Worldwide	**1,874**	**18**	2,273	29	1,858	20	1,644	19	1,577	19

* 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

	2015	2014	2013	2012	2011
Consolidated Companies					
United States					
Oil	**33,457**	32,957	33,068	32,758	32,368
Gas	**7,186**	7,098	7,740	7,737	7,671
Total United States	**40,643**	40,055	40,808	40,495	40,039
International					
Oil	**14,538**	14,017	13,776	13,299	12,802
Gas	**2,273**	2,132	2,051	2,018	2,208
Total International	**16,811**	16,149	15,827	15,317	15,010
Total Consolidated Companies	**57,454**	56,204	56,635	55,812	55,049
Equity Share in Affiliates					
Oil	**490**	486	476	456	434
Gas	**2**	2	2	2	2
Total Equity Share in Affiliates	**492**	488	478	458	436
Total Worldwide	**57,946**	56,692	57,113	56,270	55,485

[1] Net Productive Wells includes 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.

Natural Gas Realizations*

Dollars per thousand cubic feet — Year ended December 31

	2015	2014	2013	2012	2011
United States	**$ 1.92**	$ 3.90	$ 3.37	$ 2.64	$ 4.04
International	**4.53**	5.78	5.91	5.99	5.39

* 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 — Year ended December 31

	2015	2014	2013	2012	2011
United States	**$ 42.70**	$ 84.13	93.46	$ 95.21	$ 97.51
International	**46.52**	90.42	100.26	101.88	101.53

* 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 — Year ended December 31

	2015	2014	2013	2012	2011
United States	**3,913**	3,995	5,483	5,470	5,836
International	**4,299**	4,304	4,251	4,315	4,361
Total	**8,212**	8,299	9,734	9,785	10,197

* International sales include equity share in affiliates.

Natural Gas Liquids Sales*

Thousands of barrels per day — Year ended December 31

	2015	2014	2013	2012	2011
United States	**26**	20	17	16	15
International	**24**	28	26	24	24
Total	**50**	48	43	40	39

* International sales include equity share in affiliates.

Exploration and Development Costs*

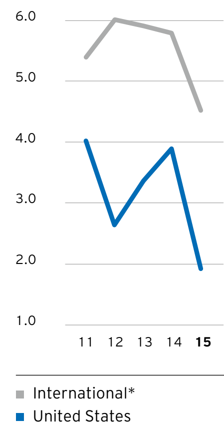
Millions of dollars — Year ended December 31

	2015	2014	2013	2012	2011
United States					
Exploration	**$ 1,144**	$ 1,222	$ 894	$ 511	$ 506
Development	**6,275**	8,207	7,457	6,597	5,517
Other Americas					
Exploration	**128**	196	627	362	175
Development	**2,048**	3,226	2,306	1,211	1,537
Africa					
Exploration	**370**	666	340	321	252
Development	**3,701**	3,771	3,549	3,118	2,698
Asia					
Exploration	**413**	543	601	558	334
Development	**3,924**	4,363	4,907	3,797	2,867
Australia/Oceania					
Exploration	**259**	396	415	434	336
Development	**6,715**	7,182	6,611	5,379	2,638
Europe					
Exploration	**108**	245	309	253	309
Development	**995**	887	1,046	753	633
Total Consolidated Companies					
Exploration	**$ 2,422**	$ 3,268	$ 3,186	$ 2,439	$ 1,912
Development	**23,658**	27,636	25,876	20,855	15,890

* Consolidated companies only. Excludes costs of property acquisitions.

Natural Gas Realizations

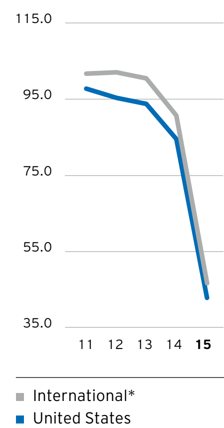
Dollars per thousand cubic feet



*Includes equity share in affiliates.

Liquids Realizations

Dollars per barrel



*Includes equity share in affiliates.

Downstream › Deliver competitive returns and grow earnings across the value chain.

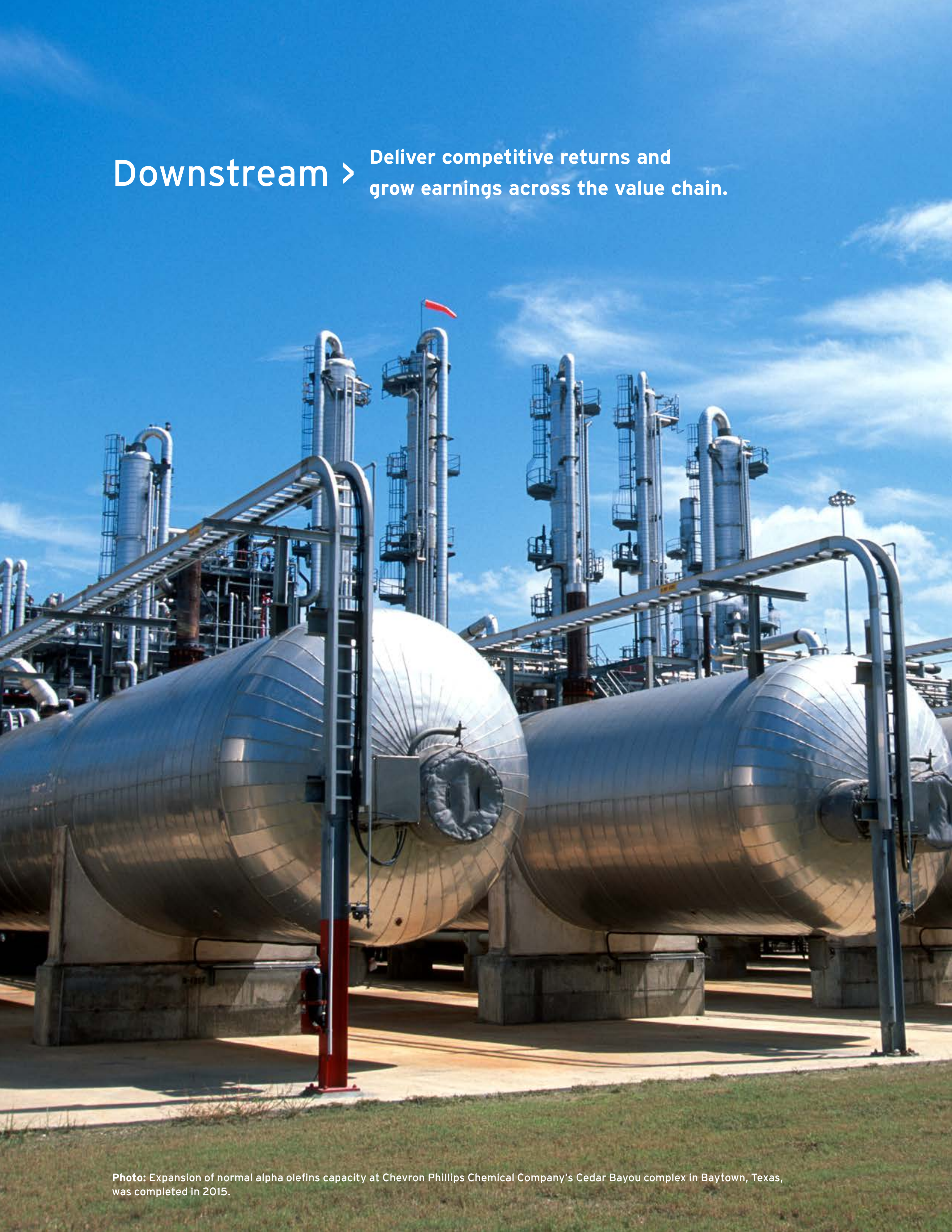
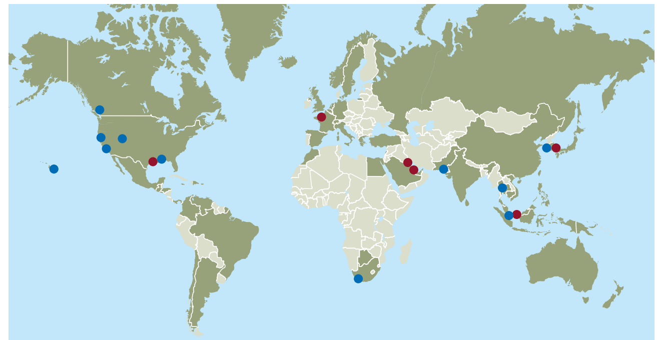


Photo: Expansion of normal alpha olefins capacity at Chevron Phillips Chemical Company's Cedar Bayou complex in Baytown, Texas, was completed in 2015.

Highlights

Downstream has a strong presence in the refining, marketing, trading and transporting of fuels and in the manufacture and distribution of lubricants, additives and petrochemicals.

Downstream Overview



Business Strategies

Deliver competitive returns and grow earnings across the value chain by:

- Achieving world-class operational excellence.
- Continually improving execution of base business.
- Driving earnings across the crude-to-customer value chain.
- Pursuing targeted growth opportunities.
- Adding value to the Upstream.

Fundamental to the company's competitive position and success is the focus on operational excellence in order to drive strong reliability and safety performance. The company continues to seek top-tier returns and cost efficiencies and to execute capital projects with excellence. Efforts to drive earnings across the value chain include aligning the highest-return markets and sales channels with manufacturing assets and utilizing technology capability. The company selectively pursues targeted growth opportunities in 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.

2015 Accomplishments

- Outperformed targets for total-recordable-injury rate, loss of containment incidents, and petroleum spill volume to land and water.
- Achieved the best year in over a decade for mechanical availability at the company-operated refineries and strong utilization rates across the network. Nonoperated refineries also continued to deliver strong performance on these measures.
- Reported best year on record, with $7.6 billion in earnings for downstream businesses.
- Realized proceeds of $3.8 billion from divestment of nonstrategic assets, primarily from the sale of its 50 percent interest in Caltex Australia Limited.
- Began commercial operations of a 100,000-metric-ton-per-year expansion of normal alpha olefins capacity at the Cedar Bayou complex in Baytown, Texas (50 percent-owned).
- Advanced construction of a petrochemicals project that includes an ethane cracker with an annual design capacity of 1.5 million metric tons of ethylene and two 500,000-metric-ton-per-year polyethylene units in Texas (all 50 percent-owned).
- Progressed construction of a gasoline desulfurization facility and a cogeneration plant at the Singapore Refinery (50 percent-owned).
- Received remaining regulatory approvals to complete the modernization of the Richmond, California, refinery.

2016 Outlook

The downstream business will continue to focus on delivering top-tier returns and to grow earnings across the value chain. Key objectives include:

- Continue to focus on safety and refinery reliability.
- Advance projects that further enhance energy efficiency, high-value product yield and refinery feedstock flexibility.
- Progress projects in the chemicals manufacturing business that add capacity and use market positions to capture global opportunities.
- Continue to focus toward higher growth and higher-margin products.

Downstream Financial and Operating Highlights

(Includes equity share in affiliates)

Dollars in Millions	2015	2014
Earnings	$ 7,601	$ 4,336
Refinery crude oil inputs (Thousands of barrels per day)	1,702	1,690
Refinery capacity at year-end (Thousands of barrels per day)	1,835	1,900
U.S. gasoline and jet fuel yields (Percent of U.S. refinery production)	63 %	64 %
Refined product sales (Thousands of barrels per day)	2,735	2,711
Motor gasoline sales (Thousands of barrels per day)	1,010	1,018
Olefin and polyolefin sales (Thousands of metric tons per year)	3,837	3,814
Specialty, aromatic and styrenic sales (Thousands of metric tons per year)	1,353	2,792
Number of marketing retail outlets at December 31	13,946	16,377
Capital expenditures	$ 2,436	$ 2,590

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 North America, Asia-Pacific and South Africa.

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.

Americas Products

The business serves retail and commercial customers in the United States, Latin America and Canada, through the world-class Chevron and Texaco brands. The company serves customers at approximately 8,800 Chevron- and Texaco-branded retail outlets and approximately 50 airports across these markets.

The Americas Products portfolio includes six wholly owned refineries in North America with a crude capacity of approximately 1 million barrels per day. Many of these refineries have large hydroprocessing units that provide the flexibility to process a wide range of feedstocks into clean, high-value products. Chevron is pursuing the possible divestment of the Hawaii Refinery and related assets.

The network of service stations is supported and served by approximately 40 proprietary fuel terminals. During 2015, the business sold a daily average of approximately 1.4 million barrels of gasoline and other refined products.

Improving Refining Flexibility, Reliability and Yield

During 2015, the company continued work on projects to improve refinery flexibility and reliability and the capability to process lower-cost feedstocks. At the Richmond, California, refinery, the company received all remaining regulatory approvals in 2015 to resume construction of its modernization project. Engineering is being finalized, and construction activity is expected to restart in 2016. This investment will replace some of the refinery's processing equipment with more modern technology that meets or exceeds the nation's toughest applicable environmental and safety standards. Start-up is expected in 2018.

Photo: Richmond Refinery modernization project.

Sustaining a Focused Marketing Portfolio

In select markets in the western and Gulf Coast regions of the United States, the company enjoys strong market positions and continues to capture opportunities to grow market share of motor gasoline and diesel fuel under the premium Chevron and Texaco brands. A loyalty program with a leading grocery chain, coupled with the company's growth strategy, has helped enable the Chevron brand to maintain a leading market position on the West Coast.

International Products

The business provides premium-quality Caltex-branded fuel products to retail and commercial customers in Asia-Pacific, Africa and the Middle East.

The International Products business includes five refineries anchored by two large affiliates in South Korea and Singapore. Other refinery assets are located in South Africa, Thailand and Pakistan. The refinery network, including the company's share of affiliates, has a crude capacity of 817,000 barrels per day. The refining assets are concentrated in Asia-Pacific and well positioned to supply expected growth in this region.

The company and its affiliates serve customers at approximately 5,100 Caltex-branded retail outlets and approximately 50 airports in Asia-Pacific, Africa and the Middle East. The business sold a daily average of 1.3 million barrels of refined products in 2015.

Photo: Caltex retail station.

In April 2015, Chevron sold its 50 percent interest in Caltex Australia Limited, which owns a refinery, fuel terminals and gas stations. Post-sale, Chevron executed agreements to provide Caltex Australia with continued product supply, technical support and ongoing licensing of the Caltex trademark.

In June 2015, the company sold its interests in a refinery in New Zealand. Chevron signed a sales and purchase agreement for the sale of all remaining marketing and lubricants assets in New Zealand. This transaction is expected to close in second quarter 2016, pending government approval.

In July 2015, the company divested its retail and commercial fuels businesses in Pakistan. Chevron has signed an agreement for the sale of its interest in a refinery in Pakistan. The agreement is pending government approval.

In addition, the company is evaluating the sale of its interests in the Cape Town Refinery, along with the marketing and lubricants businesses in South Africa.

Refineries Strategically Positioned

The 50 percent-owned Yeosu Refinery in South Korea remains one of the world's largest. 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.

During 2015, Singapore Refining Company, Chevron's 50 percent-owned joint venture, progressed construction of a gasoline desulfurization facility and cogeneration plant. This investment is expected to increase the refinery's capability to produce higher-value gasoline and improve energy efficiency. Start-up is expected in 2017.

Photo: Construction progressed on a cogeneration plant at the Singapore Refining Company.

Sustaining a Focused Marketing Portfolio

The company continues to expand in selected growth markets by executing its strategic network plan, which includes converting from company-owned, retailer-operated service stations into retailer-owned, retailer-operated sites — the model of the majority of the Caltex retail network. Rollout of partnerships with several Asian and South African convenience stores continued in 2015 with enhanced consumer loyalty and reward programs.

Lubricants

Chevron is among the leading global developers and marketers of lubricants and is the worldwide leader in premium base oil, with a total capacity of 57,000 barrels per day. The company provides high-quality lubricants products to meet the needs of commercial, industrial, consumer 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 Richmond, California, Pascagoula, Mississippi, and Yeosu, South Korea, refineries. It also includes 18 equity-blending facilities, multiple contract-blending facilities and distribution hubs. The company is well positioned to supply markets around the world and consistently meet customer needs safely and reliably. 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.

Expanding in Key Growth Markets

In 2015, the company secured new customers in key growth segments, including commercial fleet, construction, mining, power generation, and oil and gas, as well as large-scale original equipment manufacturers and motor vehicle makers.

The focus continues to be on building distribution channels and the marketer network worldwide, with an emphasis on key growth markets in the Asia-Pacific and Americas regions.

Supply and Trading

The supply and trading operation provides commercial support to Chevron's global refining and marketing businesses by maximizing efficiencies in the sourcing of raw material and product movement, optimizing product sales, and managing market risk associated with holding physical positions in crude and finished products. The supply and trading operation also provides commercial support to Chevron's global upstream operations by maximizing the company's equity crude oil and natural gas revenues. Activities include the integration of equity crude from Chevron's upstream operations into the company's refining network and the commercialization of Chevron's equity liquefied natural gas (LNG) volumes.

Chemicals

The company's chemical activities are conducted through three businesses, Chevron Phillips Chemical Company (CPChem), Chevron Oronite Company (Oronite) 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 2015, CPChem had 34 manufacturing facilities and two research and development centers around the world.

Leveraging Advantaged Feedstock Position

During 2015, flexible feedstock capability in the United States allowed CPChem to capitalize on lower input costs.

In second quarter 2015, CPChem completed construction and started commercial operations of a 100,000-metric-ton-per-year expansion of normal alpha olefins production capacity at its Cedar Bayou Plant in Baytown, Texas.

In 2015, construction advanced on the U.S. Gulf Coast Petrochemicals Project with the setting of two polyethylene reactors, completion of the critical vessel lifts and continued assembly of the ethylene furnaces. The project is expected to capitalize on advantaged feedstock sourced from shale resource development in North America. The project includes an ethane cracker with an annual design capacity of 1.5 million metric tons of ethylene at the Cedar Bayou facility and two polyethylene units located adjacent to the Sweeny complex, in Old Ocean, Texas, with a combined annual design capacity of 1.0 million metric tons. In 2016, construction activities are planned to continue. Start-up is expected in 2017.

Photo: Construction of the polyethylene units at Old Ocean, Texas, is progressing.

Oronite

Oronite 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 2015, 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

With its global manufacturing coverage and versatile cross-continent supply network, Oronite has a strong foundation to support long-term international growth. In particular, with the majority of global volume growth expected in Asia, Oronite is well positioned, with its Singapore plant being the largest additives manufacturing plant in the region.

Construction on a new carboxylate plant in Singapore progressed during 2015. Carboxylate is an effective, sulfur-free detergent often used in high-performance additive packages. With a similar unit already in place in Gonfreville, France, Oronite's global carboxylate capacity will approximately double when the project is complete. Start-up is expected in 2017.

Photo: Oronite's additive manufacturing plant in Gonfreville, France, is a key hub in its global supply chain.

In March 2015, Oronite signed an investment agreement to build an additive manufacturing plant in Ningbo, China. The plant design is under development, with a final investment decision expected by 2018.

GS Caltex

Chevron also maintains an important role in the petrochemicals business through the operations of GS Caltex, a 50 percent-owned affiliate. GS Caltex is a leading manufacturer of petrochemicals, especially aromatics. Its production capacity stands at 2.7 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 food packaging, laboratory equipment, textiles and more.

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, NGL, refined product and chemical pipelines and other infrastructure assets in the United States. In addition, Chevron operates pipelines for its 50 percent-owned CPChem affiliate. The company also has direct and indirect interests in other U.S. and international pipelines.

Refer to pages 23 and 24 in the upstream section for information on the West African Gas Pipeline, the Baku-Tbilisi-Ceyhan Pipeline, the Western Route Export Pipeline and the Caspian Pipeline Consortium.

Shipping

The company's marine fleet includes both U.S.- and foreign-flagged vessels. The U.S.-flagged vessels are engaged in transporting refined products, primarily in the coastal waters of the United States. The foreign-flagged vessels are engaged primarily in transporting crude oil from the Middle East, Southeast Asia, the Black Sea, South America, Mexico and West Africa to ports in the United States, Europe, Australia and Asia, as well as refined products and feedstocks to and from various locations worldwide. In 2015, the company took delivery of two additional LNG carriers in support of its developing LNG portfolio. Together with 2014 deliveries, four of the six new LNG vessels have been delivered to the fleet.

In addition to providing marine transportation services, the company is staffed with a team of marine technical and operational professionals who are responsible for managing marine risk across the company, assisting with marine project conceptual and feasibility studies, conducting marine project engineering and design work, and providing marine project construction and operations support.

Refinery Capacities and Crude Oil Inputs

Thousands of barrels per day	Refinery Capacity At December 31, 2015	Refinery Crude Oil Inputs (Year ended December 31) 2015	2014	2013	2012	2011
United States – Consolidated						
El Segundo, California	**269**	**258**	221	235	265	244
Kapolei, Hawaii	**54**	**47**	47	39	46	47
Pascagoula, Mississippi	**330**	**322**	329	304	335	327
Richmond, California	**257**	**245**	229	153	142	192
Salt Lake City, Utah	**53**	**52**	45	43	45	44
Total United States – Consolidated	**963**	**924**	871	774	833	854
International – Consolidated						
Canada – Burnaby, British Columbia	**55**	**46**	49	42	49	43
South Africa – Cape Town[1]	**110**	**69**	72	78	79	77
Thailand – Map Ta Phut[2]	**165**	**164**	141	161	95	–
United Kingdom – Pembroke[3]	**–**	**–**	–	–	–	122
Total International – Consolidated	**330**	**279**	262	281	223	242
International – Equity Shares in Affiliates						
Australia – Lytton (50%)[4]	**–**	**12**	50	44	46	43
Australia – Kurnell (50%)[4]	**–**	**–**	39	56	54	48
Martinique – Fort-de-France (11.5%)[5]	**–**	**–**	–	–	–	1
New Zealand – Whangarei (11.4%)[6]	**–**	**5**	13	14	13	14
Pakistan – Karachi (7.5%)	**4**	**3**	4	4	4	4
Singapore – Pulau Merlimau (50%)	**145**	**118**	109	114	128	128
South Korea – Yeosu (50%)	**393**	**361**	342	351	359	355
Thailand – Map Ta Phut (64% interest)[2]	**–**	**–**	-	-	42	98
Total International – Equity Share in Affiliates	**542**	**499**	557	583	646	691
Total International	**872**	**778**	819	864	869	933
Total Worldwide	**1,835**	**1,702**	1,690	1,638	1,702	1,787

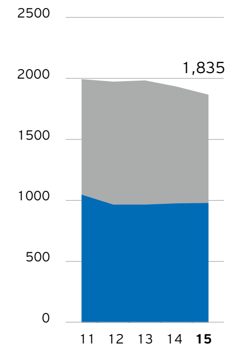
[1] Chevron holds a 75 percent controlling interest in the shares issued by Chevron South Africa (Pty) Limited, which owns the Cape Town Refinery. A consortium of South African partners, along with the employees of Chevron South Africa (Pty) Limited, own the remaining 25 percent.
[2] As of June 2012, the Map Ta Phut, Thailand, refinery is reported on a 100 percent consolidated basis. Prior to June 2012, crude-input volumes reflect a 64 percent equity interest. Chevron's ownership in this refinery was reduced to 60.6 percent following the December 2015 new share issuance and listing in Thailand by Star Petroleum Refining Public Company Limited.
[3] Chevron sold this refinery in August 2011.
[4] Chevron sold its interest in Caltex Australia Limited in April 2015.
[5] Chevron sold its interest in this refinery in August 2011.
[6] Chevron sold its interest in this refinery in June 2015.

Refinery Capacities at Year-End 2015

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**	**65**	**46**	**68**	**–**
Kapolei, Hawaii	**54**	**21**	**–**	**–**	**–**
Pascagoula, Mississippi	**330**	**86**	**97**	**98**	**25**
Richmond, California	**257**	**80**	**151**	**–**	**20**
Salt Lake City, Utah	**53**	**14**	**–**	**8**	**–**
Total United States – Consolidated	**963**	**266**	**294**	**174**	**45**
International – Consolidated					
Canada – Burnaby, British Columbia	**55**	**18**	**–**	**–**	**–**
South Africa – Cape Town	**110**	**22**	**–**	**11**	**–**
Thailand – Map Ta Phut	**165**	**41**	**–**	**–**	**–**
Total International – Consolidated	**330**	**81**	**–**	**11**	**–**
International – Equity Shares in Affiliates					
Pakistan – Karachi (7.5%)	**4**	**–**	**–**	**–**	**–**
Singapore – Pulau Merlimau (50%)	**145**	**23**	**17**	**16**	**–**
South Korea – Yeosu (50%)	**393**	**74**	**77**	**–**	**12**
Total International – Equity Share in Affiliates	**542**	**97**	**94**	**16**	**12**
Total International	**872**	**178**	**94**	**27**	**12**
Total Worldwide	**1,835**	**444**	**388**	**201**	**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 gas-oil feedstocks and hydrogen at high pressure and temperature in the presence of a solid catalyst to reduce impurities and produce lighter products, such as gasoline, diesel and jet fuel.
[5] Residuum conversion includes thermal cracking, visbreaking, coking and hydrocracking 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.

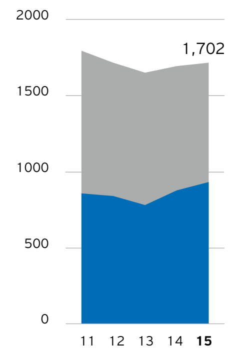
Refinery Capacity at December 31
Thousands of barrels per day



International*
United States

*Includes equity share in affiliates.

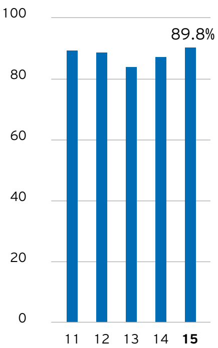
Refinery Crude Oil Inputs
Thousands of barrels per day



International*
United States

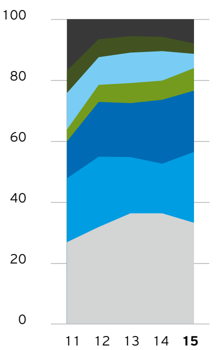
*Includes equity share in affiliates.

Worldwide Refinery Crude Distillation Utilization*
Percent of average capacity



*Includes equity share in affiliates.

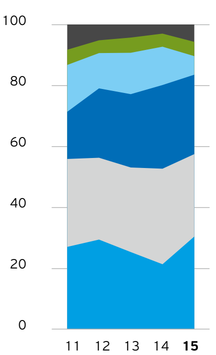
Sources of Crude Oil Input for Worldwide Refineries*
Percentage of total input



- Other
- Africa
- Mexico
- Asia-Pacific
- United States
- South America
- Middle East

*Consolidated companies only.

Sources of Crude Oil Input for U.S. Refineries
Percentage of total input



- Other
- Asia-Pacific
- Mexico
- United States
- Middle East
- South America

Refinery Crude Distillation Utilization

(Includes equity share in affiliates) — Year ended December 31

Percentage of average capacity	**2015**	2014	2013	2012	2011
United States	**96.1**	90.9	81.1	87.2	89.3
Asia-Pacific	**86.2**	84.9	88.6	91.8	90.3
Africa-Pakistan	**63.4**	65.6	71.0	71.5	69.9
Europe*	**–**	–	–	–	99.9
Other	**83.7**	89.9	76.3	89.3	77.4
Worldwide	**89.8**	86.8	83.5	88.2	88.9

* Chevron sold the Pembroke, United Kingdom, refinery in August 2011.

Sources of Crude Oil Input for Worldwide Refineries*

Year ended December 31

Percentage of total input	**2015**	2014	2013	2012	2011
Middle East	**33.1**	36.2	36.2	31.7	26.7
South America	**23.3**	16.3	18.5	23.1	21.0
United States	**20.1**	21.0	17.7	18.0	12.1
Asia-Pacific	**7.4**	6.3	6.6	5.6	3.9
Mexico	**4.7**	9.7	10.0	9.1	12.0
Africa	**3.4**	4.7	5.4	5.9	7.4
Other	**8.0**	5.8	5.6	6.6	16.9
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	**2015**	2014	2013	2012	2011
South America	**30.3**	21.2	25.2	29.3	26.9
Middle East	**27.1**	31.4	27.8	26.9	28.9
United States – excluding Alaska North Slope	**20.6**	22.5	18.1	17.4	10.1
United States – Alaska North Slope	**5.5**	5.0	6.0	5.4	5.4
Mexico	**6.1**	12.6	13.6	11.6	15.4
Asia-Pacific	**4.7**	4.3	5.0	4.2	5.0
Other	**5.7**	3.0	4.3	5.2	8.3
Total	**100.0**	100.0	100.0	100.0	100.0

Refinery Production of Refined Products

Year ended December 31

Thousands of barrels per day	**2015**	2014	2013	2012	2011
United States					
Gasoline	**439**	413	387	403	399
Gas oil	**205**	184	166	178	180
Jet fuel	**197**	196	172	192	197
Fuel oil	**38**	43	46	30	28
Other	**127**	115	97	103	113
Total United States	**1,006**	951	868	906	917
International*					
Gasoline	**94**	87	90	76	109
Gas oil	**105**	97	107	82	79
Jet fuel	**27**	25	29	24	29
Fuel oil	**26**	26	29	21	24
Other	**38**	30	32	24	10
Total International	**290**	265	287	227	251
Worldwide					
Gasoline	**533**	500	477	479	508
Gas oil	**310**	281	273	260	259
Jet fuel	**224**	221	201	216	226
Fuel oil	**64**	69	75	51	52
Other	**165**	145	129	127	123
Total Worldwide	**1,296**	1,216	1,155	1,133	1,168

* Consolidated companies only.

Refined Product Sales

Thousands of barrels per day	**2015**	2014	2013	2012	2011
	Year ended December 31				
United States					
Gasoline	**621**	615	613	624	649
Gas oil	**215**	217	195	213	213
Jet fuel	**232**	222	215	212	209
Fuel oil	**59**	63	69	68	87
Other[1]	**101**	93	90	94	99
Total United States	**1,228**	1,210	1,182	1,211	1,257
International[2]					
Gasoline	**389**	403	398	412	447
Gas oil	**478**	498	510	496	543
Jet fuel	**271**	249	245	243	269
Fuel oil	**159**	162	179	210	233
Other[1]	**210**	189	197	193	200
Total International	**1,507**	1,501	1,529	1,554	1,692
Worldwide[2]					
Gasoline	**1,010**	1,018	1,011	1,036	1,096
Gas oil	**693**	715	705	709	756
Jet fuel	**503**	471	460	455	478
Fuel oil	**218**	225	248	278	320
Other[1]	**311**	282	287	287	299
Total Worldwide	**2,735**	2,711	2,711	2,765	2,949
[1] Other primarily includes naphtha, lubricants, asphalt and coke.					
[2] Includes share of equity affiliates' sales:	**420**	475	471	522	556

Natural Gas Liquid Sales

(Includes equity share in affiliates)

Thousands of barrels per day	**2015**	2014	2013	2012	2011
	Year ended December 31				
United States	**127**	121	125	141	146
International	**65**	58	62	64	63
Total	**192**	179	187	205	209

Marketing Retail Outlets[1,2]

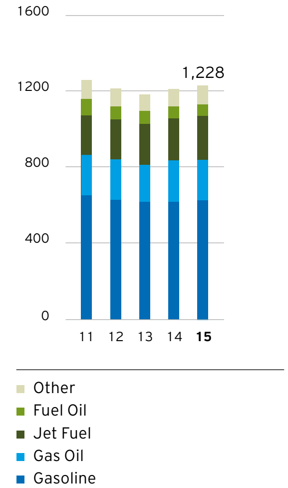
At December 31

	2015		2014		2013		2012		2011	
	Company	**Other**	Company	Other	Company	Other	Company	Other	Company	Other
United States	**366**	**7,493**	380	7,550	405	7,648	473	7,589	491	7,681
Canada	**138**	**41**	150	20	161	5	161	–	160	2
Europe	**–**	**–**	–	–	–	–	–	–	28	35
Latin America	**48**	**716**	62	679	76	627	97	587	336	835
Asia-Pacific	**174**	**1,529**	204	1,530	343	1,439	495	1,315	672	1,311
Africa-Pakistan	**191**	**633**	343	1,023	418	1,003	460	971	589	857
Total	**917**	**10,412**	1,139	10,802	1,403	10,722	1,686	10,462	2,276	10,721

[1] Excludes outlets of equity affiliates totaling 2,617, 4,436, 4,509, 4,621 and 4,834 for 2015, 2014, 2013, 2012 and 2011, 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.

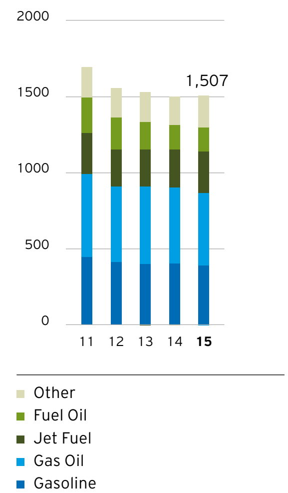
U.S. Refined Product Sales

Thousands of barrels per day



International Refined Product Sales*

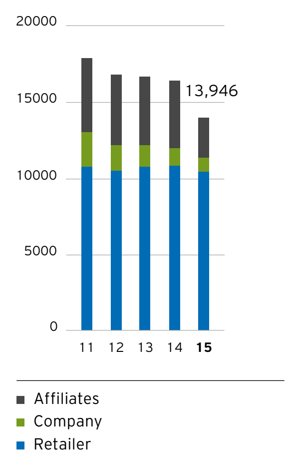
Thousands of barrels per day



*Includes equity share in affiliates.

Marketing Retail Outlets

Number of outlets



CPChem Plant Capacities and Products at Year-End 2015[1]

(Includes equity share in affiliates)

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)	–	–	835	1,060	980	465	–	√
Borger, Texas	–	–	–	–	–	–	–	√
Conroe, Texas	–	–	–	–	–	–	–	√
La Porte, Texas	–	–	–	–	–	–	–	√
Old Ocean, Texas (Sweeny)	–	–	1,955	–	–	395	–	–
Orange, Texas	–	–	–	–	440	–	–	–
Pasadena, Texas	–	–	–	–	985	–	–	–
Pascagoula, Mississippi	725	–	–	–	–	–	–	√
Port Arthur, Texas	–	480	855	–	–	350	–	–
Nine other locations	–	–	–	–	–	–	–	√
Total United States – Wholly Owned	725	480	3,645	1,060	2,405	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	3,645	1,060	2,405	1,210	475	√
International – Wholly Owned								
Belgium, Beringen	–	–	–	–	–	–	–	√
Belgium, Tessenderlo	–	–	–	–	–	–	–	√
Total International – Wholly Owned	–	–	–	–	–	–	–	√
International – Affiliates								
China, Jinshanwei (40%)	–	–	–	–	60	–	–	–
Colombia, Cartagena (50%)	–	–	–	–	–	–	–	√
Qatar, Mesaieed (49%)	–	–	255	200	395	–	–	–
Qatar, Ras Laffan (49%)	–	–	340	–	–	–	–	–
Saudi Arabia, Al Jubail (50%)	425	180	105	–	–	75	375	√
Saudi Arabia, Al Jubail (35%)	–	–	425	35	385	155	–	√
Singapore (50%)	–	–	–	–	200	–	–	–
South Korea, Yeosu (60%)	–	–	–	–	–	–	–	√
Total International – Affiliates	425	180	1,125	235	1,040	230	375	√
Total International	425	180	1,125	235	1,040	230	375	√
Total Worldwide	1,150	660	4,770	1,295	3,445	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. Actual rates may vary depending on feedstock qualities, maintenance schedules and external factors.
[3] Other includes K-Resin SBC, nylon 6,6, paraxylene, polyalphaolefins, polypropylene, polystyrene, performance pipe and specialty chemicals.

Olefin, Polyolefin, Specialty, Aromatic and Styrenic Sales

(Represents equity share in CPChem and GS Caltex)

	Year ended December 31				
Thousands of metric tons per year	**2015**	2014	2013	2012	2011
Olefin and polyolefin sales	**3,837**	3,814	3,645	3,394	3,244
Specialty, aromatic and styrenic sales	**1,353**	2,792	2,767	2,877	2,822

Technology

Photo: In 2015, a rigless multiwell hydraulic subsea well intervention was deployed at the Tahiti Field in the U.S. Gulf of Mexico.

Technology

Chevron's technology activities support the company's worldwide operations and major capital projects by developing and deploying technology solutions that drive business growth and efficiency. The company differentiates performance through the application of technology, applying a portfolio approach that includes proprietary solutions, in-house expertise, strategic partnerships and venture capital investments.

This integrated, open-innovation sourcing and deployment approach builds on the company's strengths in upstream and downstream technologies, information technology, and emerging energy.

Upstream Chevron continues advancing capabilities in subsurface imaging and modeling to support exploration, field development and reservoir management. The company integrates rapid advances in commercial seismic data acquisition techniques with proprietary imaging capability, well information, reservoir models and regional knowledge to provide a competitive advantage in geologically complex basins worldwide.

Chevron continues to expand the use of advanced seismic acquisition and processing technologies, such as interpretive and interactive seismic modeling and imaging algorithms. These technologies improve understanding of complex subsurface conditions throughout the life of assets, from the exploration stage to reservoir management. In 2015, Chevron completed deployment of a new reservoir simulation software, known as INTERSECT. The software was jointly developed by Chevron, Schlumberger and Total and is commercially available. Chevron's deployment includes proprietary modules, developed internally, that provide the company with additional competitive advantage. The INTERSECT deployment included all major capital projects and key producing assets, enabling coupled reservoir and surface network modeling and fully integrated analysis of static and dynamic uncertainties, resulting in more reliable production forecasts and optimized project performance. Utilizing INTERSECT and integrating 3-D seismic into the reservoir modeling process has resulted in improved reservoir quality and depth-structure predictions in the company's development drilling at the Wheatstone Project in Australia.

Chevron is leveraging success in applying nuclear magnetic resonance (NMR) technology to oil field applications in a best-in-industry laboratory in Houston, Texas, that was completed in 2015. Also, in 2015, Chevron partnered with the University of Western Australia to develop a reliable subsea analyzer of crude oil content in discharged water utilizing NMR technology. The next phase of development has commenced and further optimizes design for subsea installation and accommodation of high-pressure environments.

In the deep water, Chevron continues to make advances that enable the company to drill and operate safely and efficiently. In 2015, a rigless multiwell hydraulic subsea well intervention was deployed at the Tahiti Field in the U.S. Gulf of Mexico. The project represented a significant step change in the industry with an initial production uplift of 10,000 barrels of oil-equivalent per day for all five wells impacted, with a savings of $35 million per well versus a rig deployment. The project was completed under budget and minimized well shutdown duration to half of plan.

In 2015, Chevron connected two well bores together to form a nearly 4.5-mile (7.2-km) cased conduit under the Congo River submarine canyon offshore Angola. The Congo River Canyon Crossing is part of the pipeline that is designed to transport up to 250 million cubic feet per day of natural gas from Blocks 0 and 14 to the Angola liquefied natural gas (LNG) Plant. This is the largest well intersection project executed by Chevron.

The company continues to develop technology innovations in heavy oil recovery that reduce the number and cost of injectors, reduce environmental impact, and help capture previously undevelopable reserves. In 2015, Chevron surpassed 24 months of operations at the company's first horizontal steam injection well pilot in the San Joaquin Valley, California. The pilot included the successful trial of industry-advancing capability in downhole fiber-optic-based steam injection flow profiling and in the testing of multiple configurations of flow control devices for optimizing steam distribution.

Chevron continues efforts to recover more crude oil from existing fields by piloting and deploying advanced chemical enhanced oil recovery (EOR) processes. EOR deployments span the globe, and by leveraging the company's expertise in chemical formulation, reservoir characterization and production technologies, the best fields are targeted for EOR, and optimal chemical formulations are applied. In 2015, the company advanced the technical limits of high-salinity EOR chemicals and demonstrated a high-quality liquid polymer in a yard-test facility.

Advances in digital oil field technologies continue to deliver high-quality data that influence decision making. In 2015, Chevron expanded the deployment of the integrated operations center from the Captain and Alba assets in the North Sea to also include Tengizchevroil and Gorgon assets. More than $50 million in value capture was contributed from deployment in August 2014 through year-end 2015 for the Captain and Alba assets through real-time monitoring, analysis, and collaboration to optimize field management and safely maximize production.

Chevron continues to focus on eliminating low-probability, high-consequence incidents in its drilling operations. In 2015, the company expanded the capabilities of a decision support center responsible for remote, real-time monitoring of Chevron's most complex wells globally. The state-of-the-art center supports 15 drilling rigs on a 24-hour basis, providing immediate support to ensure safe, reliable and efficient operations.

Downstream Chevron continues to build on more than four decades of research and development in improved refining catalysts. In 2015, Chevron commercialized a variety of catalysts, including ICR 194 and 215 for use in hydrocracking; a new ISODEWAXING catalyst for use in base oil production; and ICR 187, a demetallation catalyst for residuum processing. Chevron continues to extend its residuum processing technology through the commercialization of LC-SLURRY™ to complete the development and licensing of this high-conversion process.

Transportation New technology continues to be applied to improve the monitoring, reliability and fuel efficiency of the company's existing vessels. In 2015, Chevron commissioned online vibration monitoring on two ships that enables the identification of risk of failure for rotating equipment onboard ships, increasing vessel reliability. Further, a predictive maintenance system is in operation on four pilot vessels that reduces the likelihood of a total loss of power or blackout event.

Chevron advanced piloting of a sloshing risk avoidance system with installation on the *Asia Endeavour,* one of the company's new LNG carriers. This system accounts for vessel characteristics, speed and weather conditions to reduce the risk of cargo tank damage.

A next-generation information technology solution has been installed on 15 of 30 vessels to reduce complexity and information risk. This technology provides reliable and scalable servers, wireless capability, and network infrastructure based on the latest Chevron technology standards.

Renewable Energy and Energy Efficiency Chevron pursues renewable energy technologies that leverage the company's strengths and can be deployed with competitive economic returns. Chevron continues to be committed to understanding and evaluating the economic viability of investments in renewable energy as the company operates one of the world's largest geothermal portfolios.

Chevron continues to believe that efficiency is an important part of the overall energy mix and is committed to improving its own energy efficiency. Beginning in 2013, Chevron adopted five segment-specific energy metrics for tracking energy performance. The company's manufacturing energy index has shown a 15 percent improvement in energy performance since 1992. Upstream energy performance has remained stable over the last five years.

Information Technology Chevron's information technology strategy has an increasingly important role in Chevron's business. Seismic data processing, remote monitoring of drilling operations, and using data science and analytics to gain insights on customer sentiments are all supported by computing infrastructure. In 2015, Chevron began operations at its new data center in San Antonio, Texas, providing increased capacity and high reliability. In addition, Chevron is making substantial investments in cybersecurity in response to increased threat levels in the industry.

Health Environment and Safety Chevron continues to improve process safety and asset integrity management through deployment of advanced technology. Reliability and integrity management of major equipment and processes are critical to base business and major capital projects, and in mid-2015, Chevron started operation of the world's first remotely-operated-vehicle-installed pipeline fatigue monitoring system. This consists of 20 retrievable sensors installed at eight stations along the Jansz-Io pipeline in Australia that are designed to collect 18 trillion data points yearly on dynamic motion, pressure and curvature. These data enable integrity management and performance of the Jansz gas supply line to the Gorgon LNG facilities. Chevron was awarded the Innovation and Development Prize at the 2014 Western Australia Engineering Excellence Awards for the Jansz-Io pipeline super-span design deployed at an underwater escarpment at the edge of the continental shelf.

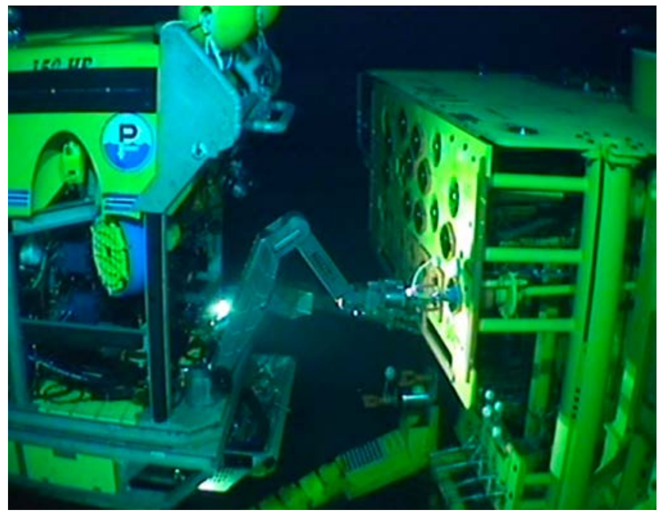


Photo: Remotely operated vehicle preparing the first subsea tree at Jansz-Io for natural gas to flow to plant site.

Chevron Technology Ventures Chevron's technology ventures company supports Chevron's upstream and downstream businesses by bridging the gap between business unit needs and emerging technology solutions developed externally in the areas of emerging materials, water management, information technology, power systems and production enhancement. In 2015, the company managed more than $350 million in venture capital investments involving the introduction or deployment of more than 20 new technologies across the enterprise, including variable speed pump drives, submersible permanent motor systems to improve artificial lift in wells and remote real-time fiber-optic surveillance technologies.

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.

Post-salt, pre-salt and subsalt *Post-salt* refers to crude oil and natural gas reservoirs lying above and deposited after an autochthonous (deposited in its present position) salt layer. *Pre-salt* refers to reservoirs lying beneath and deposited prior to an autochthonous salt layer. *Subsalt* refers to reservoirs lying beneath allochthonous (deposited at a distance from its present position) salt layers.

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 also may 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.

Renewables Energy resources that are not depleted when consumed or converted into other forms of energy (e.g., solar, geothermal, ocean and tide, wind, hydroelectric power, biofuels, and hydrogen).

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, 2015.

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.

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 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 *2015 Annual Report* to stockholders and its *Annual Report on Form 10-K* for the fiscal year ended December 31, 2015, 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
Comptroller's Department
6001 Bollinger Canyon Road, A3140
San Ramon, CA 94583-2324

The *2015 Corporate Responsibility Report* is scheduled to be available in May on the company's website, www.chevron.com, or may be requested by writing to:

Chevron Corporation
Policy, Government and Public 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.

investor information

If you have any questions regarding the data included herein, please contact:

Chevron Corporation
Investor Relations
6001 Bollinger Canyon Road, A3064
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

legal notice

As used in this report, the terms "Chevron" and "the company" 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 cost method. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

trademark notice

Caltex, Chevron, the Chevron Hallmark, Clarity, Delo, Havoline, Human Energy, ICR, ISODEWAXING, Meropa, Oronite, Rando, Taro, Techron, Texaco and Ursa are registered trademarks of Chevron Intellectual Property LLC. K-Resin is a registered trademark of Chevron Phillips Chemical Company LP. INTERSECT is a registered trademark of Schlumberger Technology Corporation.

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

This *2015 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," "may," "could," "should," "budgets," "outlook," "on schedule," "on track" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company's control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; the company's ability to realize anticipated cost savings and expenditure reductions; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of the company's suppliers, vendors, partners and equity affiliates, particularly during extended periods of low prices for crude oil and natural gas; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's operations due to war, accidents, political events, civil unrest, severe weather, cyber threats and terrorist acts, crude oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries, or other natural or human causes beyond its control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; material reductions in corporate liquidity and access to debt markets; the 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 21 through 23 of the company's *2015 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 "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 50 and 51 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 2016 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 2015 Annual Report* to stockholders and should be read in conjunction with it. The financial information contained in this *2015 Supplement to the Annual Report* is expressly qualified by reference to the *2015 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 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 provide a targeted, high-quality core acreage position primarily in the Marcellus Shale.

2015 Annual Report

2015 Supplement to the Annual Report

2015 Corporate Responsibility Report

Produced by Comptroller's Department, Chevron Corporation **Printing** ColorGraphics, Los Angeles, California

Chevron Corporation
6001 Bollinger Canyon Road, San Ramon, CA 94583-2324 USA
www.chevron.com

MIX
Paper from responsible sources
FSC® C102835

10% Recycled 100% Recyclable

912-0976