CHEVRON CORP
Form 10-K
February 22, 2013

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

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012
OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 001-00368
Chevron Corporation
(Exact name of registrant as specified in its charter)

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

Registrant's telephone number, including area code (925) 842-1000

Securities registered pursuant to Section 12 (b) of the Act:

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes o No þ

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter — $207,005,770,000 (As of June 29, 2012)

Number of Shares of Common Stock outstanding as of February 11, 2013 — 1,942,697,787

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2013 Annual Meeting and 2013 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company's 2013 Annual Meeting of Stockholders (in Part III)

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

This Annual Report on Form 10-K of Chevron Corporation contains forward-looking statements relating to Chevron's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "forecasts, "projects," "believes," "seeks," "schedules," "estimates," "budgets," "outlook" and similar expressions are intended to identify 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; 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 equity affiliates; 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 production or manufacturing facilities or delivery/transportation networks due to war, accidents, political events, civil unrest, severe weather or crude oil production quotas that might be imposed by the Organization of Petroleum Exporting Countries; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant investment or product changes required by existing or future environmental statutes, regulations and litigation; 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; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; and the factors set forth under the heading "Risk Factors" on pages 28 through 30 in this report. In addition, such results could be affected by general domestic and international economic and political conditions. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

PART I

Item 1. Business

General Development of Business

Summary Description of Chevron

Chevron Corporation,* a Delaware corporation, manages its investments in subsidiaries and affiliates and provides administrative, financial, management and technology support to U.S. and international subsidiaries that engage in fully integrated petroleum operations, chemicals operations, mining activities, power generation and energy services. Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation and regasification associated with liquefied natural gas; transporting crude oil by major international oil export pipelines; transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations consist primarily of refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lubricant additives.

A list of the company's major subsidiaries is presented on pages E-4 and E-5. As of December 31, 2012, Chevron had approximately 62,000 employees (including about 3,700 service station employees). Approximately 31,000 employees (including about 3,400 service station employees), or 50 percent, were employed in U.S. operations.

Overview of Petroleum Industry

Petroleum industry operations and profitability are influenced by many factors. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. The members of the Organization of Petroleum Exporting Countries (OPEC) are typically the world's swing producers of crude oil and their production levels are a major factor in determining worldwide supply. Demand for crude oil and its products and for natural gas is largely driven by the conditions of local, national and global economies, although weather patterns and taxation relative to

other energy sources also play a significant part. Laws and governmental policies, particularly in the areas of taxation, energy and the environment affect where and how companies conduct their operations and formulate their products and, in some cases, limit their profits directly.

Strong competition exists in all sectors of the petroleum and petrochemical industries in supplying the energy, fuel and chemical needs of industry and individual consumers. Chevron competes with fully integrated, major global petroleum companies, as well as independent and national petroleum companies, for the acquisition of crude oil and natural gas leases and other properties and for the equipment and labor required to develop and operate those properties. In its downstream business, Chevron competes with fully integrated, major petroleum companies and other independent refining, marketing, transportation and chemicals entities and national petroleum companies in the sale or acquisition of various goods or services in many national and international markets.

Operating Environment

Refer to pages FS-2 through FS-8 of this Form 10-K in Management’s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company’s current business environment and outlook.

Chevron’s Strategic Direction

Chevron’s primary objective is to create shareholder value and achieve sustained financial returns from its operations that will enable it to outperform its competitors. In the upstream, the company’s strategies are to grow profitably in core areas, build new legacy positions and commercialize the company’s equity natural gas resource base while growing a high-impact global natural gas business. In the downstream, the strategies are to improve returns and grow earnings across the value chain. The company also continues to utilize technology across all its businesses to differentiate performance, and to invest in profitable renewable energy and energy efficiency solutions.

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

Description of Business and Properties

The upstream and downstream activities of the company and its equity affiliates are widely dispersed geographically, with operations and projects* in North America, South America, Europe, Africa, Asia and Australia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2012, and assets as of the end of 2012 and 2011 — for the United States and the company's international geographic areas — are in Note 10 to the Consolidated Financial Statements beginning on page FS-36. Similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are in Notes 11 and 12 on pages FS-38 through FS-40.

Capital and Exploratory Expenditures

Total expenditures for 2012 were $34.2 billion, including $2.1 billion for the company's share of equity-affiliate expenditures. In 2011 and 2010, expenditures were $29.1 billion and $21.8 billion, respectively, including the company's share of affiliates' expenditures of $1.7 billion in 2011 and $1.4 billion in 2010.

Of the $34.2 billion in expenditures for 2012, 89 percent, or $30.4 billion, was related to upstream activities. Approximately 89 and 87 percent was expended for upstream operations in 2011 and 2010, respectively. International upstream accounted for about 72 percent of the worldwide upstream investment in 2012, about 68 percent in 2011 and about 82 percent in 2010. These amounts exclude the acquisition of Atlas Energy, Inc., in 2011.

In 2013, the company estimates capital and exploratory expenditures will be $36.7 billion, including $3.3 billion of spending by affiliates. Approximately 90 percent of the total, or $33 billion, is budgeted for exploration and production activities, with $25.5 billion, or about 70 percent, of this amount for projects outside the United States.

Refer also to a discussion of the company's capital and exploratory expenditures on page FS-12.

Upstream

The table on the following page summarizes the net production of liquids and natural gas for 2012 and 2011 by the company and its affiliates. Worldwide oil-equivalent production was 2.610 million barrels per day, down about 2 percent from 2011. The decrease was mainly associated with normal field declines, the shut-in of the Frade Field in Brazil, and a major planned turnaround at the Tengizchevroil facilities in Kazakhstan. The start-up and ramp-up of several major capital projects — the Platong II natural gas project in Thailand, the Usan and Agbami 2 projects in Nigeria, and the Perdido, Tahiti 2 and Caesar/Tonga projects in the U.S. Gulf of Mexico — partially offset the decrease in net production from 2011. Refer to the "Results of Operations" section beginning on page FS-6 for a detailed discussion of the factors explaining the 2010 through 2012 changes in production for crude oil and natural gas liquids, and natural gas.

The company estimates its average worldwide oil-equivalent production in 2013 will be approximately 2.650 million barrels per day based on an average Brent price of $112 per barrel in 2012. This estimate is subject to many factors and uncertainties, including quotas 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 project start-ups and ramp-ups, 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 longer-term outlook for 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. Refer to the “Review of Ongoing Exploration and Production Activities in Key Areas,” beginning on page 9, for a discussion of the company’s major crude oil and natural gas development projects.

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* 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.

Net Production of Crude Oil and Natural Gas Liquids and Natural Gas [1]

	Oil-Equivalent (Thousands of Barrels per Day)		Components of Oil-Equivalent Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day)		Natural Gas (Millions of Cubic Feet per Day)	
	2012	2011	2012	2011	2012	2011
United States	655	678	455	465	1,203	1,279
Other Americas						
Argentina	22	27	21	26	4	4
Brazil	6	35	6	33	2	13
Canada	69	70	68	69	4	4
Colombia	36	39	—	—	216	234
Trinidad and Tobago	29	31	—	—	173	183
Total Other Americas	162	202	95	128	399	438
Africa						
Angola	137	147	128	139	53	50
Chad	23	26	22	25	6	6
Democratic Republic of the Congo	3	3	2	3	1	1
Nigeria	269	260	242	236	165	142
Republic of the Congo	19	23	17	21	13	10
Total Africa	451	459	411	424	238	209
Asia						
Azerbaijan	28	28	26	26	10	10
Bangladesh	94	74	2	2	550	434
China	21	22	20	20	9	10
Indonesia	198	208	158	166	236	253
Kazakhstan	61	62	37	38	139	144
Myanmar	16	14	—	—	94	86
Partitioned Zone[2]	90	91	86	88	21	20
Philippines	24	25	4	4	120	126
Thailand	243	209	67	65	1,060	867
Total Asia	775	733	400	409	2,239	1,950
Australia	99	101	28	26	428	448
Europe						
Denmark	36	44	24	29	74	91
Netherlands	9	7	2	2	42	31
Norway	3	3	3	3	1	1
United Kingdom	66	85	46	59	122	155
Total Europe	114	139	75	93	239	278
Total Consolidated Companies	2,256	2,312	1,464	1,545	4,746	4,602
Equity Affiliates[3]	354	361	300	304	328	339
Total Including Affiliates[4]	2,610	2,673	1,764	1,849	5,074	4,941

[1] Includes synthetic oil: Canada, net	43	40	43	40	—	—
Venezuelan affiliate, net	17	32	17	32	—	—

[2] Located between Saudi Arabia and Kuwait.

[3] Volumes represent Chevron's share of production by affiliates, including Tengizchevroil in Kazakhstan and Petroboscan, Petroindependiente and Petropiar in Venezuela.

[4] Volumes include natural gas consumed in operations of 586 million and 582 million cubic feet per day in 2012 and 2011, respectively. Total "as sold" natural gas volumes were 4,488 million and 4,359 million cubic feet per day for 2012 and 2011, respectively.

Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-67 for the company's average sales price per barrel of crude oil, condensate and natural gas liquids and per thousand cubic feet of natural gas produced, and the average production cost per oil-equivalent barrel for 2012, 2011 and 2010.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2012 for the company and its affiliates:

Productive Oil and Gas Wells at December 31, 2012

	Productive Oil Wells		Productive Gas Wells	
	Gross	Net	Gross	Net
United States	50,180	32,758	14,248	7,737
Other Americas	736	548	48	28
Africa	2,579	861	17	7
Asia	13,127	11,335	3,148	1,924
Australia	815	458	65	11
Europe	330	97	227	48
Total Consolidated Companies	67,767	46,057	17,753	9,755
Equity Affiliates	1,300	456	7	2
Total Including Affiliates	69,067	46,513	17,760	9,757
Multiple completion wells included above	876	602	407	369

Reserves

Refer to Table V beginning on page FS-67 for a tabulation of the company's proved net crude oil and natural gas reserves by geographic area, at the beginning of 2010 and each year-end from 2010 through 2012. Reserves governance, technologies used in establishing proved reserves additions, and major changes to proved reserves by geographic area for the three-year period ended December 31, 2012, are summarized in the discussion for Table V. Discussion is also provided regarding the nature of, status of and planned future activities associated with the development of proved undeveloped reserves. The company recognizes reserves for projects with various development periods, sometimes exceeding five years. The external factors that impact the duration of a project include scope and complexity, remoteness or adverse operating conditions, infrastructure constraints, and contractual limitations.

The net proved reserve balances at the end of each of the three years 2010 through 2012 are shown in the following table.

Net Proved Reserves at December 31

	2012	2011	2010
Liquids — Millions of barrels			

Consolidated Companies	4,353	4,295	4,270
Affiliated Companies	2,128	2,160	2,233
Total Liquids	6,481	6,455	6,503
Natural Gas — Billions of cubic feet			
Consolidated Companies	25,654	25,229	20,755
Affiliated Companies	3,541	3,454	3,496
Total Natural Gas	29,195	28,683	24,251
Oil-Equivalent — Millions of barrels			
Consolidated Companies	8,629	8,500	7,729
Affiliated Companies	2,718	2,736	2,816
Total Oil-Equivalent	11,347	11,236	10,545

Acreage

At December 31, 2012, the company owned or had under lease or similar agreements undeveloped and developed crude oil and natural gas properties throughout the world. The geographical distribution of the company's acreage is shown in the following table.

Acreage at December 31, 2012
(Thousands of Acres)

	Undeveloped*		Developed		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States	6,399	5,161	7,788	5,008	14,187	10,169
Other Americas	26,913	15,898	1,348	365	28,261	16,263
Africa	8,848	3,840	3,328	1,373	12,176	5,213
Asia	30,795	14,189	1,487	857	32,282	15,046
Australia	11,427	5,728	918	239	12,345	5,967
Europe	5,481	4,153	648	126	6,129	4,279
Total Consolidated Companies	89,863	48,969	15,517	7,968	105,380	56,937
Equity Affiliates	938	430	259	102	1,197	532
Total Including Affiliates	90,801	49,399	15,776	8,070	106,577	57,469

* The gross undeveloped acres that will expire in 2013, 2014 and 2015 if production is not established by certain required dates are 1,254, 3,629 and 3,141, respectively.

Delivery Commitments

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

In the United States, the company is contractually committed to deliver to third parties 192 billion cubic feet of natural gas through 2015. The company believes it can satisfy these contracts through a combination of equity production from the company's proved developed U.S. reserves and third-party purchases. These commitments include a variety of pricing terms, including both indexed and fixed-price contracts.

Outside the United States, the company is contractually committed to deliver a total of 791 billion cubic feet of natural gas to third parties from 2013 through 2015 for operations in Australia, Colombia, Denmark and the Philippines. These sales contracts contain variable pricing formulas that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed reserves in these countries.

Development Activities

Refer to Table I on page FS-62 for details associated with the company's development expenditures and costs of proved property acquisitions for 2012, 2011 and 2010.

The following table summarizes the company's net interest in productive and dry development wells completed in each of the past three years, and the status of the company's development wells drilling at December 31, 2012. A "development well" is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Development Well Activity

	Wells Drilling at 12/31/12		Net Wells Completed 2012		2011		2010	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	78	45	941	6	909	9	634	7
Other Americas	13	6	50	—	37	—	32	—
Africa	10	4	23	—	29	—	33	—
Asia	75	35	566	15	549	15	445	15
Australia	8	4	—	—	—	—	—	—
Europe	5	—	9	—	6	—	4	—
Total Consolidated Companies	189	94	1,589	21	1,530	24	1,148	22
Equity Affiliates	6	3	26	—	25	—	8	—
Total Including Affiliates	195	97	1,615	21	1,555	24	1,156	22

Exploration Activities

Refer to Table I on page FS-62 for detail on the company's exploration expenditures and costs of unproved property acquisitions for 2012, 2011 and 2010.

The following table summarizes the company's net interests in productive and dry exploratory wells completed in each of the last three years, and the number of exploratory wells drilling at December 31, 2012. "Exploratory wells" are wells drilled to find and produce crude oil or natural gas in unproved areas and include delineation and appraisal wells, which are wells drilled to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir or to extend a known reservoir beyond the proved area.

Exploratory Well Activity

	Wells Drilling at 12/31/12		Net Wells Completed 2012		2011		2010	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry

United States	11	8	4	—	5	1	1	1
Other Americas	2	1	8	—	1	—	—	1
Africa	1	—	1	2	1	—	1	—
Asia	1	1	12	3	10	1	5	5
Australia	1	1	3	—	4	1	5	2
Europe	1	1	1	2	—	1	—	—
Total Consolidated Companies	17	12	29	7	21	4	12	9
Equity Affiliates	—	—	—	—	1	—	—	—
Total Including Affiliates	17	12	29	7	22	4	12	9

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron's 2012 key upstream activities, some of which are also discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations, beginning on page FS-2, are presented below. The comments include references to "total production" and "net production," which are defined under "Production" in Exhibit 99.1 on page E-11.
The discussion that follows references the status of proved reserves recognition for significant long-lead-time projects not on production and for projects recently placed on production. Reserves are not discussed for exploration activities or recent discoveries that have not advanced to a project stage, or for mature areas of production that do not have individual projects requiring significant levels of capital or exploratory investment. Amounts indicated for project costs represent total project costs, not the company's share of costs for projects that are less than wholly owned.

Chevron has exploration and production activities in most of the world's major hydrocarbon basins. The company's upstream strategy is to grow profitably in core areas, build new legacy positions and commercialize the company's equity natural gas resource base while growing a high-impact global natural gas business. The map above indicates Chevron's primary areas for exploration and production.

United States

Upstream activities in the United States are concentrated in California, the Gulf of Mexico, Colorado, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming. Average net oil-equivalent production in the United States during 2012 was 655,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2012, net daily production averaged 163,000 barrels of crude oil, 70 million cubic feet of natural gas and 4,000 barrels of natural gas liquids (NGLs). Approximately

86 percent of the crude oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

During 2012, net daily production for the company's combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region, was 153,000 barrels of crude oil, 395 million cubic feet of natural gas and 16,000 barrels of NGLs.
Chevron was engaged in various exploration and development activities in the deepwater Gulf of Mexico during 2012. The Jack and St. Malo fields are located within 25 miles of each other and are being jointly developed. Chevron has a 50 percent interest in the Jack Field, a 51 percent interest in the St. Malo Field and a 50.7 percent interest in the production host facility. Both fields are company operated. Drilling operations progressed during 2012, with five of 10 planned wells drilled. At the end of 2012, project activities were more than 57 percent complete, with subsea and floating production unit installation activities expected in second-half 2013. The facility is planned to have a design capacity of 177,000 barrels of oil-equivalent per day to accommodate production from the Jack/St. Malo development, which is estimated to have maximum total daily production of 94,000 barrels of oil equivalent, plus production from a nearby third-party field. Total project costs for the initial phase of development are estimated at $7.5 billion and start-up is expected in 2014. The fields have an estimated production life of 30 years. Proved reserves have been recognized for this project.
In 2012, an evaluation of additional development opportunities was initiated for the Jack and St. Malo fields. Stage 2, the first phase of future development work, is expected to include four additional development wells, two each at the Jack and the St. Malo fields. Front-end engineering and design (FEED) activities are planned to begin in mid-2013. At the end of 2012, proved reserves had not been recognized for the Jack/St. Malo Stage 2 project.

Fabrication and development drilling continued in 2012 for the 60 percent-owned and operated Big Foot project. The development plan includes a 15-slot drilling and production platform with water injection facilities and a design capacity of 79,000 barrels of oil equivalent per day. At the end of 2012, project activities were 68 percent complete, and topside module installation is planned for mid-2013. First production is anticipated in 2014. The field has an estimated production life of 20 years. Proved reserves have been recognized for this project.

Tahiti 2 is the second development phase for the 58 percent-owned and operated Tahiti Field, and is designed to increase recovery and return production to more than 100,000 barrels of crude oil per day. The project includes two additional production wells, three water injection wells and water injection facilities. Drilling commenced on the first production well in early 2012, and water injection began in first quarter 2012. Start-up of the first production well is expected by third quarter 2013. Proved reserves have been recognized for the Tahiti 2 project, and the field has an estimated production life of 30 years.

The company has a 42.9 percent nonoperated working interest in the Tubular Bells Field. Development drilling began in second quarter 2012, and plans include three producing and two injection wells, with a subsea tieback to a third-party production facility. First oil is anticipated in 2014, and maximum total daily production is expected to reach 40,000 to 45,000 barrels of oil-equivalent. The field has an estimated production life of 25 years. The initial recognition of proved reserves for the project occurred in 2012.

Chevron has a 20.3 percent nonoperated working interest in the Caesar and Tonga area. First production occurred in first quarter 2012, and maximum total daily production reached about 62,000 barrels of oil-equivalent by year-end 2012. Drilling operations on the fourth development well concluded in early 2013, and the well is expected to commence production in second quarter 2013.

The company has a 15.6 percent nonoperated working interest in the Mad Dog II Project. FEED commenced in second quarter 2012 and a final investment decision is expected in 2014. The project includes the construction and installation of a new production and drilling spar facility and is expected to add incremental maximum total daily production of 120,000 to 140,000 barrels of oil equivalent. At the end of 2012, proved reserves had not been recognized for this project.

In 2012, Chevron signed commercial agreements for the Stampede project allowing for the joint development of the Knotty Head and Pony fields. Chevron holds a 20 percent nonoperated working interest in this joint development. The project is expected to enter FEED by mid-2013. At the end of 2012, proved reserves had not been recognized for this project.

Deepwater exploration activities in 2012 included participation in three exploratory wells — one appraisal and two wildcats. Drilling began on an appraisal well at the

43.8 percent-owned and operated Moccasin discovery in fourth quarter 2012. Drilling activities were placed on hold in early 2013 for equipment repair and are expected to resume later this year. Moccasin and the 55 percent-owned and operated Buckskin discovery, located 12 miles apart, could be jointly developed upon the successful completion of additional appraisal drilling planned for 2013. A second Coronado wildcat well began drilling in second quarter 2012, targeting the lower Tertiary Wilcox formation. Drilling was completed in February 2013, and the results are under evaluation. Chevron also had a 20 percent nonoperated working interest in the Hummer Shallow wildcat well.

Chevron added 15 leases to the deepwater portfolio as a result of awards from the central Gulf of Mexico lease sale in mid-2012. In addition, Chevron submitted the highest bids on 28 additional deepwater leases at the western Gulf of Mexico lease sale in late 2012.

Besides the activities connected with development and exploration projects in the Gulf of Mexico, the company also has contracted liquefied natural gas (LNG) offloading, storage and regasification capacity at the Sabine Pass LNG facility and natural gas transportation capacity in a third-party pipeline system connecting the terminal to the U.S. natural gas pipeline grid.

Company activities in the mid-continental United States include operated and nonoperated interests in properties primarily in Colorado, New Mexico, Oklahoma, Texas and Wyoming. During 2012, the company’s net daily production in these areas averaged 90,000 barrels of crude oil, 600 million cubic feet of natural gas and 29,000 barrels of NGL's.

In West Texas, the company continues to pursue development of tight oil and liquids-rich shale resources in the Midland Basin’s Wolfcamp play and several plays in the Delaware Basin through use of advanced drilling and completion technologies. Additional production growth is expected from interests in these formations in future years. In October 2012, an acquisition of more than 350,000 gross acres in New Mexico augmented the company's leasehold position in the Delaware Basin and surrounding areas.

The company holds leases in the Marcellus Shale and Utica Shale, primarily located in southwestern Pennsylvania, Ohio, and West Virginia, and in the Antrim Shale in Michigan. During 2012, the company's net daily production in these areas averaged approximately 138 million cubic feet of natural gas. In 2012, development of the Marcellus Shale proceeded at a measured pace, focused on improving execution capability and reservoir understanding. Activities in the Utica Shale during 2012 included acquisition of regional seismic data in eastern Ohio to identify core areas. The company commenced drilling on four exploratory wells during the year. This initial activity was focused on acquiring data necessary for potential future development. The company also holds a 49 percent interest in Laurel Mountain Midstream, LLC, an affiliate that owns more than 1,200 miles of natural gas gathering lines servicing the Marcellus.

Other Americas

“Other Americas” is composed of Argentina, Brazil, Canada, Colombia, Suriname, Trinidad and Tobago, and Venezuela. Net oil-equivalent production from these countries averaged 230,000 barrels per day during 2012, including the company’s share of synthetic oil production.

Canada: Chevron has interests in oil sands projects and shale acreage in Alberta, shale acreage and an LNG project in British Columbia, exploration, development and production projects offshore in the Atlantic region, and exploration and discovered resource interests in the Beaufort Sea region of the Northwest Territories. Average net oil-equivalent production during 2012 was 69,000 barrels per day, composed of 25,000 barrels of crude oil, 4 million cubic feet of natural gas and 43,000 barrels of synthetic oil from oil sands.

The company holds a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP). Oil sands are mined from both the Muskeg River and the Jackpine mines and bitumen is extracted from the oil sands and upgraded into synthetic oil. During 2012, ramp-up from the AOSP Expansion 1 Project continued to boost production toward the total daily design capacity of approximately 255,000 barrels. Additionally, a final investment decision was reached in mid-2012 on the Quest Project, a carbon capture and sequestration project that is designed to capture and store more than one million tons annually of carbon dioxide produced by bitumen processing at the AOSP by 2015.

In February 2013, Chevron acquired a 50 percent-owned and operated interest in the Kitimat LNG project and proposed Pacific Trail Pipeline, and a 50 percent nonoperated working interest in 644,000 total acres in the Horn River and Liard shale gas basins in British Colombia. The Kitimat project is planned to include a two-train, 10.0 million-metric-ton-per-year LNG facility, and at the time of acquisition, FEED activities were in progress.

Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field and a 23.6 nonoperated working interest in the unitized Hibernia Southern Extension (HSE) offshore Atlantic Canada. The HSE development is expected to increase the economic life of the Hibernia Field. Fabrication of topside and subsea equipment progressed in 2012. Full production start-up is expected in 2014. Proved reserves have been recognized for the initial wells drilled.

The company holds a 26.6 percent nonoperated working interest in the heavy-oil Hebron Field, also offshore Atlantic Canada. The development plan includes a concrete, gravity-based platform with a capacity of 150,000 barrels of crude oil per day. The maximum total daily crude oil production is expected to be 134,000 barrels. FEED activities were completed in 2012, and a final investment decision was made in December 2012. Project costs are estimated at $14 billion. The project has an expected economic life of 30 years, and first oil is expected in 2017. The initial recognition of proved reserves for the project occurred in 2012.

During 2012, drilling continued on a multiwell program on the 100 percent-owned and operated leases in the Duvernay shale formation in Alberta. The company also holds exploration licenses and leases in the Flemish Pass and Orphan basins offshore Atlantic Canada and the Beaufort Sea region of the Northwest Territories, including a 35.4 percent nonoperated working interest in the offshore Amauligak discovery.

In addition, Chevron holds interests in the Aitken Creek and Alberta Hub natural gas storage facilities, which have aggregate total capacity of approximately 100 billion cubic feet. These facilities are located in western Canada near the Duvernay, Horn River, Liard and Montney shale gas plays.

Greenland: In December 2012, Chevron relinquished its 29.2 percent nonoperated working interest in Exploration License 2007/26, which includes Block 4 offshore West Greenland.

Argentina: Chevron holds operated interests in four concessions in the Neuquen Basin. Working interests range from 18.8 percent to 100 percent. Net oil-equivalent production in 2012 averaged 22,000 barrels per day, composed of 21,000 barrels of crude oil and 4 million cubic feet of natural gas. During 2012, two exploratory wells targeting shale gas and tight oil resources were drilled in the Vaca Muerta formation in the El Trapial concession. In early 2013, a third exploratory well commenced drilling and the results of the previous wells were under evaluation. Chevron plans to drill three additional appraisal wells in 2013. The El Trapial concession expires in 2032.

Brazil: Chevron holds working interests in three deepwater fields in the Campos Basin: Frade (51.7 percent-owned and operated), Papa-Terra and Maromba (37.5 percent and 30 percent nonoperated working interests, respectively). Net oil-equivalent production in 2012 averaged 6,000 barrels per day, composed of 6,000 barrels of crude oil and 2 million cubic feet of natural gas.

In March 2012, production was suspended as a precautionary measure at the Frade Field while studies were conducted to better understand the geology in the area. Production is expected to partially resume in 2013 subject to necessary regulatory approvals. The concession that includes the Frade Field expires in 2025.

During 2012, construction activities and development drilling continued for the Papa-Terra project. The project includes a floating production, storage and offloading vessel (FPSO) and a tension leg wellhead platform, with a design capacity of 140,000 barrels of crude oil per day. First production is expected in second-half 2013. Proved reserves have been recognized for this project. Evaluation of the field development concept for Maromba continued in 2012 with submission of an initial Plan of Development to the authorities in September. At the end of 2012, proved reserves had not been recognized for this project. These concessions expire in 2032.

Colombia: The company operates the offshore Chuchupa and the onshore Ballena and Riohacha natural gas fields as part of the Guajira Association contract. In exchange, Chevron receives 43 percent of the production for the remaining life of each field and a variable production volume based on prior Chuchupa capital contributions. Daily net production averaged 216 million cubic feet of natural gas in 2012.

Suriname: In November 2012, Chevron acquired a 50 percent nonoperated working interest in Blocks 42 and 45 offshore Suriname. Under the agreements, the company would assume the role of operator in the event of commercial discoveries. In 2013, planned exploration activities include seismic data acquisition and processing.

Trinidad and Tobago: The company has a 50 percent nonoperated working interest in three blocks in the East Coast Marine Area offshore Trinidad, which includes the Dolphin and Dolphin Deep producing natural gas fields and the Starfish development. Net production in 2012 averaged 173 million cubic feet of natural gas per day. Development of the Starfish Field commenced in third quarter 2012, and first gas is expected in 2014. Natural gas from the project will supply existing contractual commitments. Proved reserves have been recognized for this project. Chevron also holds a 50 percent-owned and operated interest in the Manatee Area of Block 6(d) where the Manatee discovery comprises a single cross-border field with Venezuela's Loran Field in Block 2. In 2012, work continued on maturing commercial development concepts.

Venezuela: Chevron holds interests in two producing affiliates located in western Venezuela and one producing affiliate in the Orinoco Belt. Chevron has a 30 percent interest in the Petropiar affiliate that operates the Hamaca heavy-oil production and upgrading project located in Venezuela's Orinoco Belt, a 39.2 percent interest in the Petroboscan affiliate that operates the Boscan Field in the western part of the country, and a 25.2 percent interest in the Petroindependiente affiliate that operates the LL-652 Field in Lake Maracaibo. The company's share of net oil-equivalent production during 2012 from these operations averaged 68,000 barrels per day, composed of 64,000 barrels of liquids and 27 million cubic feet of natural gas.

Chevron holds a 34 percent interest in the Petroindependencia affiliate that is working toward commercialization of Carabobo 3, a heavy-oil project located within the Carabobo Area of the Orinoco Belt. During 2012, work continued on conceptual engineering for the potential development project.

The company operates and has a working interest of 60 percent in Block 2 in the Plataforma Deltana area offshore eastern Venezuela, which includes the Loran Field. During 2012, work continued on maturing commercial development concepts.

Africa

In Africa, the company is engaged in upstream activities in Angola, Chad, Democratic Republic of the Congo, Liberia, Morocco, Nigeria, Republic of the Congo, Sierra Leone and South Africa. Net oil-equivalent production in Africa averaged 451,000 barrels per day during 2012.

Angola: Chevron holds company-operated working interests in offshore Blocks 0 and 14 and nonoperated working interests in offshore Block 2 and the onshore Fina Sonangol Texaco (FST) area. Net production from these operations in 2012 averaged 137,000 barrels of oil-equivalent per day.

The company operates the 39.2 percent-owned Block 0, which averaged 98,000 barrels per day of net liquids production in 2012. The Block 0 concession extends through 2030.

Work on the second development stage of the Mafumeira Field in Block 0 continued in 2012. Mafumeira Sul, a project to develop the southern portion of the field, reached a final investment decision in 2012. Development plans include a central processing facility, two wellhead platforms, subsea pipelines, and 34 producing and 16 water injection wells. First production is planned for 2015, with maximum total production expected to reach 110,000 barrels of crude oil and 10,000 barrels of liquefied petroleum gas (LPG) per day. The project is estimated to cost $5.6 billion. The initial recognition of proved reserves for this project occurred in 2012.

A project to develop the Greater Vanza/Longui Area of Block 0 is scheduled to enter FEED in second-half 2013. FEED activities continued during 2012 on the south extension of the N'Dola Field development with a final investment decision expected in 2014. The facility is planned to have a design capacity of 28,000 barrels of crude oil per day. At the end of 2012, proved reserves had not been recognized for these projects.

Work continued in 2012 on the final stage of the Nemba Enhanced Secondary Recovery Stage 1 and 2 Project in Block 0. Installation activities are scheduled to begin in 2013, and project start-up is expected in early 2015. Maximum total production is expected to reach 13,000 barrels of oil-equivalent per day. Proved reserves have been recognized for this project.

Also in Block 0, drilling commenced on a post-salt/pre-salt dual objective exploration well in Area A in late 2012 and was completed in early 2013. The results are under evaluation. An additional pre-salt exploration well in Area A is planned for second-half 2013, along with one pre-salt and one post-salt appraisal well in Area B.

In the 31 percent-owned Block 14, net production in 2012 averaged 28,000 barrels of liquids per day. Development and production rights for the various producing fields in Block 14 expire between 2023 and 2028.

In June 2012, the project to develop the Lucapa Field in Block 14 entered FEED. Development plans include an FPSO and 17 subsea wells. The facility is planned to have a design capacity of 80,000 barrels of crude oil per day. A final investment decision is expected in 2014. During the year, development alternatives were evaluated for the Malange Field, and the project is expected to enter FEED in mid-2013. At the end of 2012, proved reserves had not been recognized for these projects.

In addition to the exploration and production activities in Angola, Chevron has a 36.4 percent interest in Angola LNG Limited, which will operate an onshore natural gas liquefaction plant in Soyo, Angola. The plant is designed 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. The plant reached mechanical completion, and commissioning activities continued through 2012. The first LNG shipment from the plant is expected to occur in second quarter 2013. The project is

estimated to cost $10 billion. The anticipated economic life of the project is in excess of 20 years. Proved reserves have been recognized for the producing operations associated with this project.

The company also holds a 38.1 percent interest in a pipeline project that is designed to transport up to 250 million cubic feet of natural gas per day from Block 0 and Block 14 to the Angola LNG plant. Construction on the project continued in 2012, and the project is expected to be completed in 2014.

Angola-Republic of the Congo Joint Development Area: Chevron operates and holds a 31.3 percent interest in the Lianzi development zone, located in an area shared equally by Angola and the Republic of the Congo. A final investment decision for the Lianzi development project was reached in July 2012. The project scope includes four producing wells and three water injection wells with a subsea tieback to an existing platform in Block 14. First production is anticipated in 2015, and maximum total daily production is expected to be 46,000 barrels of crude oil. The initial recognition of proved reserves for the project occurred in 2012.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2012 averaged 3,000 barrels of oil-equivalent.

Republic of the Congo: Chevron has a 31.5 percent nonoperated working interest in the Haute Mer permit areas (Nkossa, Nsoko and Moho-Bilondo) and a 29.3 percent nonoperated working interest in the Kitina permit area, all of which are offshore. The licenses for Kitina, Nsoko, Nkossa and Moho-Bilondo expire in 2014, 2018, 2027 and 2030, respectively. Net production averaged 19,000 barrels of oil-equivalent per day in 2012.

FEED activities for the Moho Nord project, located in the Moho-Bilondo development area, continued in 2012. The project includes a new facilities hub and a subsea tieback to the existing Moho-Bilondo floating production unit. Maximum total daily production is expected to be 127,000 barrels of crude oil per day. A final investment decision is expected in first quarter 2013 and start-up is planned for 2015. At the end of 2012, proved reserves had not been recognized for this project.

Chad/Cameroon: Chevron has a 25 percent nonoperated working interest in crude oil producing operations in southern Chad, and an approximate 21 percent interest in two affiliates that own an export pipeline that transports crude oil to the coast of Cameroon. Average daily net production from the Chad fields in 2012 was 23,000 barrels of oil-equivalent. The Chad producing operations are conducted under a concession that expires in 2030.

Nigeria: Chevron holds a 40 percent interest in 13 concessions, predominantly in the onshore and near-offshore regions of the Niger Delta. The company operates under a joint-venture arrangement in this region with the Nigerian National Petroleum Corporation, which owns a 60 percent interest. The company also owns varying interests in four operated and six nonoperated deepwater blocks. In 2012, the company's net oil-equivalent production in Nigeria averaged 269,000 barrels per day, composed of 238,000 barrels of crude oil, 165 million cubic feet of natural gas and 4,000 barrels of LPG.

Chevron operates and holds a 67.3 percent interest in the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128. During 2012, drilling continued on a 10-well, Phase 2 development program, Agbami 2, that is expected to offset field decline and maintain plateau production. The first well in this program commenced production in second quarter 2012. The leases that contain the Agbami Field expire in 2023 and 2024.

The company holds a 30 percent nonoperated working interest in the deepwater Usan project in OML 138. Production commenced in first quarter 2012, and total daily production at year-end 2012 was 81,000 barrels of crude oil and 3 million cubic feet of natural gas. The facilities have a maximum total production capacity of 180,000 barrels of crude oil per day. The production-sharing contract (PSC) expires in 2023.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in OML 118 share a common geologic structure and are planned to be jointly developed. The project is expected to enter FEED in 2013. At the end of 2012, no proved reserves were recognized for this project.

In the Niger Delta, the company reached a final investment decision in early 2013 on the Dibi Long-Term Project that is designed to rebuild the Dibi facilities and replace the Early Production System facility. The facilities are planned to have a maximum production capacity of 70,000 barrels of crude oil per day, and start-up is expected in 2016.

Also in the Niger Delta, ramp-up activity continued at the Escravos Gas Plant (EGP). During 2012, construction continued on Phase 3B of the EGP project, which is designed to gather 120 million cubic feet of natural gas per day from eight offshore fields and to compress and transport the natural gas to onshore facilities. The Phase 3B project is expected to be completed in 2016. Proved reserves associated with this project have been recognized.

The 40 percent-owned and operated Sonam Field Development is designed to process natural gas through EGP, deliver 215 million cubic feet of natural gas per day to the domestic market and produce a total of 30,000 barrels of liquids per day. First production is expected in 2016. Proved reserves have been recognized for the project.

Chevron has a 75 percent-owned and operated interest in a gas-to-liquids facility at Escravos that is being developed with the Nigerian National Petroleum Corporation. The 33,000-barrel-per-day facility is designed to process 325 million cubic feet per day of natural gas supplied from the Phase 3A expansion of EGP. As of early 2013, overall work on the project was more than 89 percent complete and start-up is planned for late 2013. The estimated cost of the plant is $9.5 billion.

The company has a 40 percent-owned and operated interest in the Onshore Asset Gas Management project that is designed to restore approximately 125 million cubic feet per day of natural gas production from certain onshore fields that have been shut in since 2003 due to civil unrest. Construction was completed in third quarter 2012, and start-up commenced in late 2012.

In deepwater exploration, the company has a 27 percent nonoperated working interest in Oil Prospecting License (OPL) 223 where an exploration well was drilled in third quarter 2012. In addition, Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery in OML 140. Additional exploration activities are planned for 2013 and 2014.

Shallow-water exploration activities in 2012 included reprocessing 3-D seismic data from OML 86 and OML 88 and regional mapping activities.

With a 36.7 percent interest, Chevron is the largest shareholder in the West African Gas Pipeline Company Limited affiliate, which owns and operates the 421-mile 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 per day.

Liberia: Chevron operates three deepwater blocks off the coast of Liberia. In July 2012, the company farmed down its interest from 70 percent to 45 percent in these blocks. Exploration wells were drilled in blocks LB-11 and LB-12 during 2012. In 2013, the company plans to mature drilling prospects based on the evaluation of 2012 drilling results and 3-D seismic data.

Morocco: In early 2013, the company entered into agreements to acquire a 75 percent operated interest in three deepwater areas offshore Morocco. The areas, Cap Rhir Deep, Cap Cantin Deep and Cap Walidia Deep, encompass approximately 7.2 million acres. Once the award is finalized, acquisition of seismic data is planned.

Sierra Leone: In September 2012, the company announced that it had been awarded operatorship and a 55 percent interest in a concession off the coast of Sierra Leone. The concession contains two deepwater blocks, with a combined area of approximately 1.4 million acres. Acquisition of 2-D seismic data is planned for 2013.

South Africa: In December 2012, the company entered into an agreement to seek shale gas exploration opportunities in the Karoo Basin in South Africa. This agreement allows Chevron and its partner to work together over a five-year period to obtain exploration permits in the 151 million-acre basin.

Asia

In Asia, the company is engaged in upstream activities in Azerbaijan, Bangladesh, Cambodia, China, Indonesia, Kazakhstan, the Kurdistan Region of Iraq, Myanmar, the Partitioned Zone located between Saudi Arabia and Kuwait, the Philippines, Russia, Thailand, and Vietnam. During 2012, net oil-equivalent production averaged 1,061,000 barrels per day.

Azerbaijan: Chevron holds an 11.3 percent nonoperated working interest in the Azerbaijan International Operating Company (AIOC), which produces crude oil from the Azeri-Chirag-Gunashli (ACG) project. The company's daily net production from AIOC averaged 28,000 barrels of oil-equivalent in 2012. AIOC operations are conducted under a PSC that expires in 2024.

During 2012, construction progressed on the next development phase of the ACG project, which will further develop the deepwater Gunashli Field. The total estimated cost of the project is $6 billion, with an incremental targeted maximum total daily production of 103,000 barrels of oil-equivalent. Production is expected to begin in late 2013. Proved reserves have been recognized for this project.

Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate, which owns and operates a crude oil export pipeline from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities at Ceyhan, Turkey. The BTC Pipeline has a capacity of 1.2 million barrels per day and transports the majority of ACG production. Another production export route for crude oil is the Western Route Export Pipeline, wholly owned and operated by AIOC, with capacity to transport 100,000 barrels per day from Baku, Azerbaijan, to a marine terminal at Supsa, Georgia.

Kazakhstan: Chevron participates in two major upstream developments in western Kazakhstan. The company holds a 50 percent interest in the Tengizchevroil (TCO) affiliate, which is operating and developing the Tengiz and Korolev crude oil fields under a concession that expires in 2033. Chevron's net oil-equivalent production in 2012 from these fields averaged 286,000 barrels per day, composed of 218,000 barrels of crude oil, 301 million cubic feet of natural gas and 18,000 barrels of NGLs. During 2012, the majority of TCO's crude oil production was exported through the Caspian Pipeline Consortium (CPC) pipeline that runs from Tengiz in Kazakhstan to tanker-loading facilities at Novorossiysk on the Russian coast of the Black Sea. The balance was exported via rail to Black Sea ports.

In 2012, FEED activities were initiated for three projects. The Wellhead Pressure Management Project is designed to maintain production capacity and extend the production plateau from existing assets. The Capacity and Reliability Project is designed to reduce facility bottlenecks and increase plant efficiency and reliability. The Future Growth Project is designed to increase total daily crude oil production by 250,000 to 300,000 barrels of oil-equivalent and to increase the ultimate recovery of the reservoir. The project will expand the utilization of sour gas injection technology proven in existing operations. The final investment decisions on these projects are planned for late 2013. At the end of

2012, proved reserves have only been recognized for the Wellhead Pressure Management Project.

Also at TCO, start-up commenced on the Sulfur Expansion Project in December 2012. This project is designed to eliminate routine additions to sulfur inventory.

In June 2012, the company's nonoperated working interest in the Karachaganak Field was reduced from 20 percent to 18 percent as a result of a 2011 agreement with the Republic of Kazakhstan government. Operations and development of the field are conducted under a PSC that expires in 2038. During 2012, Karachaganak net oil-equivalent production averaged 61,000 barrels per day, composed of 37,000 barrels of liquids and 139 million cubic feet of natural gas. Access to the CPC and Atyrau-Samara (Russia) pipelines enabled approximately 35,000 net barrels per day of Karachaganak liquids to be exported and sold at world-market prices during 2012. The remaining liquids were sold into local and Russian markets. During 2012, work continued on identifying the optimal scope for the future expansion of the field. At the end of 2012, proved reserves had not been recognized for any further expansion.

Kazakhstan/Russia: Chevron has a 15 percent interest in the CPC affiliate. During 2012, CPC transported an average of approximately 657,000 barrels of crude oil per day, including 590,000 barrels per day from Kazakhstan and 67,000 barrels per day from Russia. During 2012, work continued on the 670,000-barrel-per-day expansion of the pipeline capacity with the mechanical completion of the offshore loading system. The $5.4 billion project is expected to be implemented in three phases, with capacity increasing progressively until reaching maximum capacity of 1.4 million barrels per day in 2016. The first increase in capacity of 400,000 barrels per day is expected in 2014.

Turkey: In December 2012, Chevron relinquished its 50 percent interest in License 3921 in the Black Sea.

Bangladesh: Chevron holds a 98 percent interest in two operated PSCs covering Block 12 (Bibiyana) 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. Net oil-equivalent production from these operations in 2012 averaged 94,000 barrels per day, composed of 550 million cubic feet of natural gas and 2,000 barrels of liquids.

In April 2012, start-up of the Muchai compression project was achieved. This project supports additional natural gas production capacity of 80 million cubic feet per day from the Bibiyana, Jalalabad and Moulavi Bazar fields. The Bibiyana Expansion project achieved a final investment decision in July 2012. The project scope includes a gas plant expansion, additional development drilling and an enhanced liquids recovery unit, and is expected to increase total maximum daily production by more than 300 million cubic feet of natural gas and 4,000 barrels of condensate. First production is expected in 2014. The initial recognition of proved reserves for this expansion project occurred in 2012.

Cambodia: Chevron owns a 30 percent interest and operates the 1.2 million-acre Block A, located in the Gulf of Thailand. In 2012, the company progressed discussions on the production permit for development of Block A. The planned development consists of a wellhead platform and a floating storage and offloading vessel (FSO). A final investment decision is pending resolution of commercial terms. At the end of 2012, proved reserves had not been recognized for the 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 the natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. The company’s average net natural gas production in 2012 was 94 million cubic feet per day.

Thailand: Chevron has operated and nonoperated working interests in multiple offshore blocks in the Gulf of Thailand. The company’s net oil-equivalent production in 2012 averaged 243,000 barrels per day, composed of 67,000 barrels of crude oil and condensate and 1.1 billion cubic feet of natural gas. The company’s natural gas production is sold to the domestic market under long-term sales contracts.

The company holds operated interests in the Pattani Basin with ownership interests ranging from 35 percent to 80 percent. Concessions for producing areas within this basin expire between 2020 and 2035. Chevron has a 16 percent nonoperated working interest in the Arthit Field located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040.

During 2012, the company drilled six exploration wells in the Pattani Basin, and four were successful. The company also holds exploration interests in the Thailand-Cambodia overlapping claim area that are inactive, pending resolution of border issues between Thailand and Cambodia.

Vietnam: Chevron is the operator of two PSCs in the Malay Basin off the southwest coast of Vietnam. The company has a 42.4 percent interest in a PSC that includes Blocks B and 48/95, and a 43.4 percent interest in a PSC for Block 52/97.

The Block B Gas Development Project is designed to produce natural gas from the Malay Basin for delivery to state-owned Petrovietnam. The project includes installation of wellhead and hub platforms, an FSO, a central processing platform and a pipeline to shore. FEED continued during 2012. Maximum total daily production is expected to be 490 million cubic feet of natural gas and 4,000 barrels of condensate. A final investment decision for the development is pending resolution of commercial terms. At the end of 2012, proved reserves had not been recognized for the development project.

During 2012, the company drilled two exploratory wells in Block 52/97, and both were successful.

China: Chevron has operated and nonoperated working interests in several areas in China. The company's net oil-equivalent production in 2012 averaged 21,000 barrels per day, composed of 20,000 barrels of crude oil and condensate and 9 million cubic feet of natural gas.

The company operates and holds a 49 percent interest in the

Chuandongbei PSC, located in the onshore Sichuan Basin. The full development includes two new sour-gas processing plants with an aggregate inlet design capacity of 740 million cubic feet per day, connected by a natural gas gathering system to five fields. During 2012, the company continued construction of the first natural gas processing plant, and site preparation commenced for the second natural gas processing plant. The initial plant, with an expected maximum total production of 258 million cubic feet per day, is targeted for mechanical completion at the end of 2013. Planned maximum total natural gas production is 558 million cubic feet per day, and the total project cost is estimated to be $6.4 billion. Proved reserves have been recognized for this project. The PSC for Chuandongbei expires in 2037.

The company holds a 59.2 percent-owned and operated interest in deepwater Block 42/05 in the South China Sea, which covers exploratory acreage of approximately 1.3 million acres. During 2012, the company drilled two exploration wells in South China Sea deepwater Blocks 53/30 and 64/18, and both were unsuccessful. In November 2012, the company relinquished its interest in deepwater Blocks 53/30 and 64/18.
Additional 3-D seismic data was acquired over Block 42/05, and further exploration drilling is under evaluation. In 2012, Chevron entered into an agreement to acquire a 100 percent-owned and operated interest in shallow-water Blocks 15/10 and 15/28, which cover approximately 1.4 million exploratory acres. Government approval is expected in first-half 2013, and a 3-D seismic survey is expected to commence in mid-2013.

During 2012, the company drilled an initial exploratory well for shale gas in the Qiannan Basin. Evaluation of the well continues in early 2013. Additional drilling is planned for 2013.

The company also has nonoperated working interests of 32.7 percent in Blocks 16/08 and 16/19 in the Pearl River Mouth Basin and nonoperated working interests of 24.5 percent in the QHD 32-6 Field and 16.2 percent in Block 11/19 in the Bohai Bay.

Philippines: The company holds a 45 percent nonoperated working interest in the Malampaya natural gas field located 50 miles offshore Palawan Island. Net oil-equivalent production in 2012 averaged 24,000 barrels per day, composed of 120 million cubic feet of natural gas and 4,000 barrels of condensate. During 2012, plans progressed on Malampaya Phase 2 to drill two additional infill wells and to add depletion compression facilities. Start-up is planned for 2014. Proved reserves have been recognized for this project.

Chevron also develops and produces geothermal resources in southern Luzon, which supply steam to third-party, 637-megawatt power generation facilities. During fourth quarter 2012, Chevron sold 60 percent of its interest in these geothermal operations in order to secure a 25-year geothermal operating contract with the Philippine government for the continued development and operation of the steam fields. Chevron also has a 90 percent-owned and operated interest in the Kalinga geothermal prospect area in northern Luzon and is in the early phase of geological and geophysical assessments.

Indonesia: Chevron holds operated and nonoperated working interests in Indonesia. The company has 100 percent-owned and operated interests in the Rokan and Siak PSCs onshore Sumatra. Chevron also operates four PSCs in the Kutei Basin, located offshore East Kalimantan. These interests range from 62 percent to 92.5 percent. Chevron also has 51 percent operated working interests in two exploration blocks in western Papua, West Papua I and West Papua III, and a 25 percent nonoperated working interest in a joint venture in Block B in the South Natuna Sea.

The company's net oil-equivalent production in 2012 from its interests in Indonesia averaged 198,000 barrels per day, composed of 158,000 barrels of liquids and 236 million cubic feet of natural gas. The largest producing field is Duri, located in the Rokan PSC. Duri has been under steamflood since 1985 and is one of the world's largest steamflood developments. The North Duri Development is divided into multiple expansion areas. Construction began on the Duri Area 13 expansion project in fourth quarter 2012. First production is scheduled for late 2013, and maximum total daily production of 17,000 barrels of crude oil is expected to be reached in 2016. The Rokan PSC expires in 2021.

During 2012, two deepwater development projects in the Kutei Basin progressed under a single plan of development. In the first of these projects, Chevron completed FEED for the Gendalo-Gehem deepwater natural gas project, and a final investment decision is expected during 2014. The project includes two separate hub developments, natural gas and condensate pipelines, and an onshore receiving facility. Maximum total daily production from the project is expected to be about 1.1 billion cubic feet of natural gas and 31,000 barrels of condensate. Gas from the project is expected to be used domestically and for LNG export. The company's working interest is approximately 63 percent. At the end of 2012, proved reserves had not been recognized for this project.

In the second of these projects, the company requested bids for all major contracts for the Bangka deepwater natural gas project. A final investment decision is expected in 2013. The project scope includes a subsea tieback to a floating production unit, and maximum total daily production is expected to be about 114 million cubic feet of natural gas and 4,000 barrels of condensate. The company's working interest is 62 percent. At year-end 2012, proved reserves had not been recognized for this project.

In Sumatra, four exploration wells were drilled. Two wells were successful and the results for two wells are under evaluation in early 2013. Appraisal and exploration drilling is planned for 2013. In the West Papua exploration blocks, which are in close proximity to a third-party LNG facility, seismic data acquisition and processing was completed for West Papua I in 2012 and is planned for completion for West Papua III in 2013.

In West Java, the company operates and holds a 95 percent interest in the Darajat geothermal field, which supplies steam to a power plant with a total operating capacity of 259 megawatts. Chevron also operates and holds a 100 percent interest in the Salak geothermal field in West Java, which supplies steam to a power plant with a total operating capacity of 377 megawatts. In Sumatra, Chevron operates and holds a 95 percent interest in the North Duri Cogeneration Plant, supplying up to 300 megawatts of power to the company's Sumatra operations and steam in support of the Duri steamflood project. In the Suoh-Sekincau prospect area of Sumatra, the company holds a 95 percent-owned and operated interest in a license to explore and develop a geothermal prospect.

Kurdistan Region of Iraq: In July 2012, the company announced the acquisition of an 80 percent-owned and operated interest in two PSCs covering the Rovi and Sarta blocks in the Kurdistan Region of Iraq. The blocks cover a combined area of approximately 232,000 acres.

Partitioned Zone (PZ): Chevron holds a concession to operate the Kingdom of Saudi Arabia's 50 percent interest in the petroleum resources in the onshore area of the PZ between Saudi Arabia and Kuwait. The concession expires in 2039.

During 2012, the company's average net oil-equivalent production was 90,000 barrels per day, composed of 86,000 barrels of crude oil and 21 million cubic feet of natural gas. During 2012, the company continued a steam injection pilot project in the First Eocene carbonate reservoir that was initiated in 2009. A project to expand the steam injection pilot to the Second Eocene reservoir is expected to enter FEED by late 2013. Development planning also continued during 2012 on a full-field steamflood application in the Wafra Field. The Wafra Steamflood Stage 1 Project is expected to enter FEED in 2014. At the end of 2012, proved reserves had not been recognized for any of these steamflood developments.

Also in 2012, FEED activities continued on the Central Gas Utilization Project. The project is intended to increase natural gas utilization and eliminate routine flaring. A final investment decision is expected in 2014. At year-end 2012, proved reserves had not been recognized for this project.

Australia

In Australia, the company’s upstream efforts are concentrated off the northwest coast. During 2012, the average net oil-equivalent production from Australia was 99,000 barrels per day.

Chevron holds a 47.3 percent ownership interest across most of the Greater Gorgon Area and is the operator of the Gorgon Project, which combines the development of the Gorgon and nearby Io/Jansz natural gas fields. The development includes a three-train, 15.6 million-metric-ton-per-year LNG facility, a carbon sequestration project and a domestic natural gas plant. Maximum total daily production from the project is expected to reach approximately 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate. Start-up of the first train is expected in late 2014, leading to the first LNG cargo in first quarter 2015. Total estimated project costs for the first phase of development are $52 billion. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 40 years from the time of start-up.

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Work on the Gorgon project continued during 2012. As of year-end 2012, more than 55 percent of the project activities had been completed. Key milestones achieved in 2012 were the arrival and installation of the first LNG plant modules, subsea wellhead trees and subsea pipelines. The development drilling program also progressed during 2012.

Chevron has signed binding, long-term LNG Sales and Purchase Agreements with six Asian customers for delivery of about 4.8 million metric tons of LNG per year, which brings delivery commitments to about 65 percent of Chevron’s share of LNG from this project. Discussions continue with potential customers to increase long-term sales to 85 percent of Chevron’s net LNG offtake. Chevron also has binding long-term agreements for delivery of about 65 million cubic feet per day of natural gas to Western Australian natural gas consumers starting in 2015, and the company continues to market additional natural gas quantities from the Gorgon Project.

An expansion project to develop a fourth train at the Gorgon LNG facility is expected to enter FEED in late 2013. At the end of 2012, proved reserves had not been recognized for the fields associated with this project.

Chevron is the operator of the Wheatstone Project, which includes a two-train, 8.9 million-metric-ton-per-year LNG facility and a domestic gas plant located at Ashburton North, along the northwest coast of Australia. The company plans to supply natural gas to the facilities from three company-operated licenses, containing the Wheatstone Field and nearby Iago Field. Maximum total daily production from these and third-party fields is expected to be about 1.6 billion cubic feet of natural gas and 30,000 barrels of condensate. Start-up of the first train is expected in 2016. Total estimated project costs for the first phase of development are $29 billion. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 30 years from the time of start-up.

In 2012, construction and fabrication activities progressed, with a focus on delivering site infrastructure and key components of the platform and subsea equipment. Chevron signed additional commercial agreements that decreased Chevron's interest in the offshore licenses to 80.2 percent and in the LNG facilities to 64.1 percent. The company also executed agreements with Asian customers for the delivery of additional volumes of LNG. As of year-end 2012, more than 80 percent of Chevron’s equity LNG offtake was covered under long-term agreements with customers in Asia. In addition, the company has begun marketing its equity share of natural gas of approximately 120 million cubic feet per day to Western Australia natural gas consumers.

During 2012 and early 2013, the company announced seven natural gas discoveries in the Carnarvon Basin. These include natural gas discoveries at the 47.3 percent-owned and operated Pontus prospect in Block WA-37-L, the 50 percent-owned and operated Satyr prospect in Block WA-374-P, the 50 percent-owned and operated Pinhoe prospect in Block WA-383-P, the 50 percent-owned and operated Arnhem prospect in Block WA-364-P, and the 50 percent-owned and operated Kentish Knock South prospect in Block WA-365-P. These discoveries are expected to contribute to potential expansion opportunities at company-operated LNG facilities.

Chevron has a 16.7 percent nonoperated working interest in the North West Shelf (NWS) Venture in Western Australia. Daily net production from the project during 2012 averaged 20,000 barrels of crude oil and condensate, 428 million cubic feet of natural gas, and 4,000 barrels of LPG. Approximately 70 percent of the natural gas was sold in the form of LNG to major utilities in Asia, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market. The concession for the NWS Venture expires in 2034.

The North Rankin 2 project continued to advance during 2012, with start-up expected in mid-2013. The project is designed to recover remaining low-pressure natural gas from the North Rankin and Perseus fields to meet gas supply needs and maintain NWS production capacity of about 2 billion cubic feet of natural gas and 39,000 barrels of condensate. Total estimated projects costs are $5.4 billion. Proved reserves have been recognized for the project. The project's estimated economic life exceeds 20 years from the time of start-up.

In October 2012, the company exchanged its 16.7 percent interest in the East Browse leases and its 20 percent interest in the West Browse leases for financial consideration and a 33.3 percent interest in the WA-205-P and WA-42-R blocks in the Carnarvon Basin and now holds a 100 percent interest in these blocks, which contain the Clio and Acme fields. The company retains other nonoperated working interests ranging from 24.8 percent to 50 percent in three other blocks in the Browse Basin. In Block WA-274-P, drilling in the fourth quarter 2012 resulted in a natural gas discovery at the Crown prospect.

Europe

In Europe, the company is engaged in upstream activities in Bulgaria, Denmark, Lithuania, the Netherlands, Norway, Poland, Romania, Ukraine and the United Kingdom. Net oil-equivalent production in Europe averaged 114,000 barrels per day during 2012.

Denmark: Chevron has a 12 percent working interest in the partner-operated Danish Underground Consortium (DUC), which produces crude oil and natural gas from 13 fields in the Danish North Sea. Net oil-equivalent production in 2012 from DUC averaged 36,000 barrels per day, composed of 24,000 barrels of crude oil and 74 million cubic feet of natural gas. In July 2012, as part of a 30-year concession extension, the state-owned Danish North Sea Fund received a 20 percent ownership of the DUC in exchange for the previous 20 percent government profit-take arrangements and the company's interest was reduced from 15 percent to 12 percent. The concession expires in 2042.

Netherlands: Chevron operates and holds interests ranging from 34.1 percent to 80 percent in 10 blocks in the Dutch sector of the North Sea. In 2012, the company’s net oil-equivalent production was 9,000 barrels per day, composed of 2,000 barrels of crude oil and 42 million cubic feet of natural gas.

Norway: The company holds a 7.6 percent nonoperated working interest in the Draugen Field. The company’s net production averaged 3,000 barrels of oil-equivalent per day during 2012. Chevron is the operator and has a 40 percent working interest in exploration licenses PL 527 and PL 598. Both licenses are in the deepwater portion of the Norwegian Sea.

United Kingdom: The company’s average net oil-equivalent production in 2012 from 10 offshore fields was 66,000 barrels per day, composed of 46,000 barrels of liquids and 122 million cubic feet of natural gas. Most of the production was from three fields: the 85 percent-owned and operated Captain Field, the 23.4 percent-owned and operated Alba Field, and the 32.4 percent-owned and jointly operated Britannia Field.

Procurement and fabrication activities began in 2012 for the Clair Ridge project, located west of the Shetland Islands, in which the company has a 19.4 percent nonoperated working interest. The project is the second development phase of the Clair Field. Total planned design capacity is 120,000 barrels of crude oil per day, and the total estimated cost of the project is $7 billion. Production is scheduled to begin in 2016 and the project's estimated economic life exceeds 40 years from the time of start-up. Proved reserves have been recognized for the Clair Ridge project.

At the 70 percent-owned and operated Alder discovery, FEED activities progressed during 2012, and a final investment decision is planned for late 2013. The 40 percent-owned and operated Rosebank Project northwest of the Shetland Islands entered FEED in July 2012. A final investment decision is planned for 2014. Maximum total daily production is expected to reach 64,000 barrels of liquids and 42 million cubic feet of natural gas. At the end of 2012, proved reserves had not been recognized for these projects.

An unsuccessful exploration well was drilled at the Aberlour prospect west of the Shetland Islands. Full and partial block relinquishments were made during 2012 under Licenses P119 (Strathspey area), P1026, P1191 and P1194 (Aberlour).

Bulgaria: In June 2011, the Bulgarian government advised that Chevron had submitted a winning tender for a permit for exploration in a 1.1 million-acre area in northeast Bulgaria. In January 2012, prior to execution of the license agreement, the Bulgarian government announced the withdrawal of the decision awarding the permit and the Bulgarian parliament imposed a ban on hydraulic fracturing, a technology commonly used for shale development and production. Chevron continues to work with the government of Bulgaria to provide the necessary assurances to both the government and the public that hydrocarbons from shale can be developed safely and responsibly.

Lithuania: In October 2012, Chevron acquired a 50 percent interest in a Lithuanian exploration and production company. In 2013, the affiliate plans to commence shale exploration activities in the 394,000-acre Rietavas block.

Poland: Chevron holds four shale concessions in southeast Poland (Frampol, Grabowiec, Krasnik and Zwierzyniec). All four exploration licenses are 100 percent-owned and operated and comprise a total of 1.1 million acres. During 2012, drilling was completed on the first well in the Grabowiec concession and evaluation of this well continued into early 2013. An initial well was also drilled in the Frampol concession in 2012. Drilling of a well in the Zwierzyniec concession commenced in

December 2012, and continued exploratory drilling of the concessions is planned for 2013.

Romania: The company holds a 100 percent interest and operates the Barlad shale concession. This license is located in northeast Romania and covers 1.6 million acres. Drilling of an exploration well is planned for second-half 2013. In March 2012, three additional petroleum concession agreements, covering approximately 670,000 acres in southeast Romania, were approved by the government of Romania. Chevron holds a 100 percent interest and operates the concessions. Acquisition of 2-D seismic data across these concessions is expected to commence in second-half 2013.

Ukraine: In 2012, Chevron was the successful bidder for the right to exclusively negotiate a 50-year PSC with the government of Ukraine for the Oleska block in western Ukraine. Chevron is expected to operate and hold a 50 percent interest in the 1.6 million-acre concession. As of early 2013, the PSC and Joint Operating Agreement terms were being negotiated.

Sales of Natural Gas and Natural Gas Liquids

The company sells natural gas and natural gas liquids from its producing operations under a variety of contractual arrangements. In addition, the company also makes third-party purchases and sales of natural gas and natural gas liquids in connection with its trading activities.

During 2012, U.S. and international sales of natural gas were 5.5 billion and 4.3 billion cubic feet per day, respectively, which includes the company’s share of equity affiliates’ sales. Outside the United States, substantially all of the natural gas sales from the company’s producing interests are from operations in Australia, Bangladesh, Europe, Kazakhstan, Indonesia, Latin America, Myanmar, Nigeria, the Philippines and Thailand.

U.S. and international sales of natural gas liquids were 157 thousand and 88 thousand barrels per day, respectively, in 2012. Substantially all of the international sales of natural gas liquids from the company's producing interests are from operations in Africa, Kazakhstan, Indonesia and the United Kingdom.

Refer to “Selected Operating Data,” on page FS-10 in Management’s Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company’s sales volumes of natural gas and natural gas liquids. Refer also to “Delivery Commitments” on page 7 for information related to the company’s delivery commitments for the sale of crude oil and natural gas.

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Downstream

Refining Operations

At the end of 2012, the company had a refining network capable of processing about 2.0 million barrels of crude oil per day. Operable capacity at December 31, 2012, and daily refinery inputs for 2010 through 2012 for the company and affiliate refineries are summarized in the table below.

Average crude oil distillation capacity utilization during 2012 was 88 percent, compared with 89 percent in 2011. At the U.S. refineries, crude oil distillation capacity utilization averaged 87 percent in 2012, compared with 89 percent in 2011. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 77 percent and 85 percent of Chevron's U.S. refinery inputs in 2012 and 2011, respectively.

At the Pascagoula Refinery, construction progressed on a facility to produce approximately 25,000 barrels per day of premium base oil for use in manufacturing high-performance finished lubricants, such as motor oils for consumer and commercial applications. Mechanical completion is expected by year-end 2013. In July 2012, the company completed the sale of its idled 80,000-barrel-per-day Perth Amboy, New Jersey, refinery, which was operating as a terminal.

At the refinery in El Segundo, a new processing unit designed to further improve the facility's overall reliability, enhance high-value product yield and provide additional flexibility to process a broad range of crude slates came online in July 2012. Similar projects were progressed in 2012 at the Salt Lake City and Pascagoula refineries and are scheduled to be completed in late 2013.

Outside the United States, GS Caltex, a 50 percent-owned equity affiliate, reached mechanical completion of a 53,000-barrel-per-day gas oil fluid catalytic cracking unit at the Yeosu Refinery in South Korea in early 2013. The unit is designed to increase high-value product yield and lower feedstock costs. In 2012, construction was completed on modifications to the 64 percent-owned Star Petroleum Refinery in Thailand to meet regional specifications for cleaner fuels. Also in 2012, Caltex Australia Ltd., a 50 percent-owned equity affiliate, announced plans to convert the Kurnell, Australia, refinery to an import terminal in 2014.

Petroleum Refineries: Locations, Capacities and Inputs
(Crude-unit capacities and crude oil inputs in thousands of barrels per day; includes equity share in affiliates)

		December 31, 2012		Refinery Inputs		
Locations		Number	Operable Capacity	2012	2011	2010
Pascagoula	Mississippi	1	330	335	327	325
El Segundo	California	1	269	265	244	250
Richmond	California	1	257	142	192	228
Kapolei	Hawaii	1	54	46	47	46
Salt Lake City	Utah	1	45	45	44	41
Total Consolidated Companies — United States		5	955	833	854	890
Pembroke[1]	United Kingdom	—	—	—	122	211
Map Ta Phut[2]	Thailand	1	158	95	—	—
Cape Town[3]	South Africa	1	110	79	77	70
Burnaby, B.C.	Canada	1	55	49	43	40
Total Consolidated Companies — International		3	323	223	242	321

Affiliates[2,4]	Various Locations	6	675	646	691	683
Total Including Affiliates — International		9	998	869	933	1,004
Total Including Affiliates — Worldwide		14	1,953	1,702	1,787	1,894

1 Pembroke was sold in August 2011.

2 As of June 2012, Star Petroleum Refining Company crude input volumes are reported on a consolidated basis. Prior to June 2012, crude volumes reflect a 64 percent equity interest and are reported in equity affiliates.

3 Chevron holds 100 percent of the common stock issued by Chevron South Africa (Pty) Limited, which owns the Cape Town Refinery. A consortium of South African partners owns preferred shares ultimately convertible to a 25 percent equity interest in Chevron South Africa (Pty) Limited. None of the preferred shares had been converted as of February 2013.

4 Includes 1,000 and 2,000 barrels per day of refinery inputs in 2011 and 2010, respectively, for interests in refineries that were sold during those periods.

Marketing Operations

The company markets petroleum products under the principal brands of “Chevron,” “Texaco” and “Caltex” throughout many parts of the world. The following table identifies the company’s and affiliates’ refined products sales volumes, excluding intercompany sales, for the three years ended December 31, 2012.

Refined Products Sales Volumes
(Thousands of Barrels per Day)

	2012	2011	2010
United States			
Gasoline	624	649	700
Jet Fuel	212	209	223
Gas Oil and Kerosene	213	213	232
Residual Fuel Oil	68	87	99
Other Petroleum Products[1]	94	99	95
Total United States	1,211	1,257	1,349
International[2]			
Gasoline	412	447	521
Jet Fuel	243	269	271
Gas Oil and Kerosene	496	543	583
Residual Fuel Oil	210	233	197
Other Petroleum Products[1]	193	200	192
Total International	1,554	1,692	1,764
Total Worldwide[2]	2,765	2,949	3,113

[1] Principally naphtha, lubricants, asphalt and coke.

	2012	2011	2010
[2] Includes share of equity affiliates’ sales:	522	556	562

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2012, the company supplied directly or through retailers and marketers approximately 8,060 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 470 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 8,700 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. The company markets in Latin America using the Texaco brand. In the Asia-Pacific region, southern Africa, Egypt and Pakistan, the company uses the Caltex brand. The company also operates through affiliates under various brand names. In South Korea, the company operates through its 50 percent-owned equity affiliate, GS Caltex, and in Australia through its 50 percent-owned equity affiliate, Caltex Australia Limited.

The company continued its ongoing effort to concentrate downstream resources and capital on strategic assets. In 2012, Chevron completed the sale of the company's fuels marketing, finished lubricants and aviation fuels businesses in Spain as well as certain fuels marketing and aviation businesses in eight countries in the Caribbean. The company's GS Caltex affiliate also completed the sale of certain power and other assets in South Korea. In addition, the company converted more than 240 company-operated service stations into retailer-owned sites in various countries outside the United States.

Chevron markets commercial aviation fuel at approximately 120 airports worldwide. The company also markets an extensive line of lubricant and coolant products under the brand names Havoline, Delo, Ursa, Meropa and Taro in the United States and worldwide under the three master brands: Chevron, Texaco and Caltex.

Chemicals Operations

Chevron owns a 50 percent interest in its Chevron Phillips Chemical Company LLC (CPChem) equity affiliate. At the end of 2012, CPChem owned or had joint-venture interests in 36 manufacturing facilities and two research development centers around the world.

CPChem’s 35 percent-owned equity affiliate, Saudi Polymers Company, announced commercial production at its new olefins and derivatives facility in Al-Jubail, Saudi Arabia, in October 2012. In the United States, CPChem commenced construction of a 1-hexene plant at the company’s Cedar Bayou complex in Baytown, Texas, with a design capacity of 250,000 metric tons per year. Start-up is expected in 2014. In 2012, CPChem also commenced front-end engineering and design for several projects on the U.S. Gulf Coast, which are expected to capitalize on advantaged feedstock sourced from emerging shale gas development in North America. These include an ethane cracker with an annual design capacity of 1.5 million metric tons of ethylene to be located at the Cedar Bayou complex in Baytown, Texas, and two polyethylene facilities to be located in Old Ocean, Texas, each with an annual design capacity of 500,000 metric tons.

Chevron’s Oronite brand lubricant and fuel additives business is a leading developer, manufacturer and marketer of performance additives for lubricating oils and fuels. The company owns and operates facilities in Brazil, France, Japan, the Netherlands, Singapore and the United States and has equity interests in facilities in India and Mexico. Oronite lubricant additives are blended into refined base oil to produce finished lubricant packages used primarily in engine applications such as passenger car, heavy-duty diesel, marine, locomotive and motorcycle engines, and additives for fuels that are blended to improve engine performance and extend engine life. In 2012, the company began construction on a project to expand the capacity of the existing additives plant in Singapore. The project is expected to double the plant's capacity since it was commissioned in 1999 and to begin commercial operations in 2014.

Transportation

Pipelines: Chevron owns and operates an extensive network of crude oil, refined product, chemical, natural gas liquid and natural gas pipelines and other infrastructure assets in the United States. The company also has direct and indirect interests in other U.S. and international pipelines. The company's ownership interests in pipelines are summarized in the following table.

Pipeline Mileage at December 31, 2012

	Net Mileage[1,2]
United States:	
Crude Oil	1,969
Natural Gas	2,396
Petroleum Products	6,009
Total United States	10,374
International:	
Crude Oil	696
Natural Gas	199
Petroleum Products	334
Total International	1,229
Worldwide	11,603

[1] Includes company's share of pipeline mileage owned by equity affiliates.
[2] Excludes gathering pipelines relating to the crude oil and natural gas production function.

The company continues to lead the construction of a 136-mile, 24-inch crude oil pipeline from the planned Jack/St. Malo facility to a platform in Green Canyon Block 19 on the U.S. Gulf of Mexico shelf, where there is an interconnect to pipelines delivering crude oil into Texas and Louisiana. The project is expected to be completed by start-up of the production facility in 2014.

In December 2012, the company executed agreements to sell the 100 percent-owned and operated Northwest Products System. This system consisted of a 760-mile refined products pipeline running from Salt Lake City, Utah, to Spokane, Washington, a dedicated jet fuel pipeline serving the Salt Lake City International Airport, and three refined products terminals located in Idaho and Washington. The sale is pending regulatory approval and is expected to be completed in first-half 2013. In addition, the company is in the process of relinquishing its interest in the Trans Alaska Pipeline System.

Refer to pages 14, 15, 16 and 17 in the Upstream section for information on the Chad/Cameroon pipeline, the West African Gas Pipeline, the Baku-Tbilisi-Ceyhan Pipeline, the Western Route Export Pipeline and the Caspian Pipeline Consortium.

Tankers: All tankers in Chevron's controlled seagoing fleet were utilized during 2012. During 2012, the company had 51 deep-sea vessels chartered on a voyage basis, or for a period of less than one year. The following table summarizes the capacity of the company's controlled fleet.

Controlled Tankers at December 31, 2012[1]

	U.S. Flag		Foreign Flag	
	Number	Cargo Capacity (Millions of Barrels)	Number	Cargo Capacity (Millions of Barrels)
Owned	—	—	1	1.1
Bareboat-Chartered	4	1.4	18	27.2
Time-Chartered[2]	3	1.0	11	8.9
Total	7	2.4	30	37.2

1 Consolidated companies only. Excludes tankers chartered on a voyage basis, those with dead-weight tonnage less than 25,000 and those used exclusively for storage.
2 Tankers chartered for more than one year.

The company's U.S.-flagged fleet is engaged primarily in transporting refined products 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. The company's foreign-flagged vessels also transport refined products and feedstocks to and from various locations worldwide.

In 2012, the company ordered eight new vessels, a combination of bareboat charters and new builds contracts, to modernize the fleet and increase LNG coverage. In addition to the vessels ordered in 2012, the company has prior contracts in place to build LNG carriers and a dynamic-positioning shuttle tanker to support future upstream projects. The company also owns a one-sixth interest in each of seven LNG carriers transporting cargoes for the North West Shelf Venture in Australia.

Other Businesses

Mining: Chevron's U.S.-based mining company concluded the divestment of its remaining coal mining operations. In 2012, the company completed the sale of its Kemmerer, Wyoming, surface coal mine and the sale of its 50 percent interest in Youngs Creek Mining Company, LLC, which was formed to develop a coal mine in northern Wyoming. Activities related to final reclamation continued in 2012 at the company-operated surface coal mine in McKinley, New Mexico.

Chevron also owns and operates the Questa molybdenum mine in New Mexico. At year-end 2012, Chevron had 160 million pounds of proven molybdenum reserves at Questa. Production and underground development at Questa continued at reduced levels in 2012 in response to weak prices for molybdenum.

Power Generation: Chevron's Global Power Company manages interests in 11 power assets with a total operating capacity of more than 2,200 megawatts, primarily through joint ventures in the United States and Asia. Ten of these are efficient combined-cycle and gas-fired cogeneration facilities that utilize recovered waste heat to produce electricity and support industrial thermal hosts. The 11th facility is a wind farm, located in Casper, Wyoming, that is designed to optimize the use of a decommissioned refinery site for delivery of clean, renewable energy to the local utility.

Chevron also has major geothermal operations in Indonesia and the Philippines and is evaluating several advanced solar technologies for use in oil field operations as part of its renewable energy strategy. For additional information on the company's geothermal operations and renewable energy projects, refer to page 19 in the Upstream section and "Research and Technology" below.

Chevron Energy Solutions (CES): CES is a wholly owned subsidiary that develops and builds sustainable energy projects that increase energy efficiency and production of renewable power, reduce energy costs, and ensure reliable, high-quality energy for government, education and business facilities. CES has developed hundreds of projects that have helped customers reduce their energy costs and environmental impact. In 2012, CES completed several public sector programs, including a first-of-its-kind microgrid at the Santa Rita jail in Alameda County, and renewable and efficiency programs for Huntington Beach City School District, South San Francisco Unified School District and Union City, all in California, plus Rootstown Local School District in Ohio. CES also completed an energy efficiency program at the Detroit Arsenal and a combined renewable power production and heating project at the Marine Corps Logistics Base in Albany, Georgia. CES is also guiding the work of the new Chevron Center for Sustainable Energy Efficiency in Qatar. In December 2012, CES and its partners inaugurated the first large scale solar testing in Qatar. The evaluation will help determine the most appropriate solar technologies for the Middle East.

Research and Technology: The company's energy technology organization supports Chevron's upstream and downstream businesses by providing technology, services and competency development in earth sciences; reservoir and production engineering; drilling and completions; facilities engineering; manufacturing; process technology; catalysis; technical computing; and health, environment and safety disciplines. The

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

Chevron's venture capital investment group manages investments and projects in emerging energy technologies and their integration into Chevron's core businesses. As of the end of 2012, the venture capital group continued to explore technologies such as next-generation biofuels, advanced solar and enhanced pipeline inspection methods. In 2012, the company continued evaluation of a solar-to-steam generation project in use to support enhanced-oil-recovery operations in Coalinga, California. This project was commissioned to test the viability of using solar power to produce steam to improve oil recovery.

In 2012, the company launched a new tank technology for storing water at hydraulic fracturing operations. These patent-pending modular metal tanks can be quickly assembled and taken apart for reuse at other wells. This enables drilling and fracturing without the need for water storage pits and is intended to result in enhanced safety, less land disturbance, smaller drill site pads and significantly lower costs. The first fully operational tank was brought into service in Ohio.

Chevron's research and development expenses were $648 million, $627 million and $526 million for the years 2012, 2011 and 2010, respectively.

Some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, and ultimate technical or commercial successes are not certain.

Environmental Protection: The company designs, operates and maintains its facilities to avoid potential spills or leaks and minimize the impact of those that may occur. Chevron requires its facilities and operations to have operating standards and processes and emergency response plans that address all credible and significant risks identified by site-specific risk and impact assessments. Chevron also requires that sufficient resources be available to execute these plans. In the unlikely event that a major spill or leak occurs, Chevron also maintains a Worldwide Emergency Response Team comprised of employees who are trained in various aspects of emergency response, including post-incident remediation.

To complement the company's capabilities, Chevron maintains active membership in international oil spill response cooperatives, including the Marine Spill Response Corporation, which operates in U.S. territorial waters, and Oil Spill Response, Ltd. (OSRL), which operates globally. The company is a founding member of the Marine Well Containment Company, whose primary mission is to expediently deploy containment equipment and systems to capture and contain crude oil in the unlikely event of a future loss of control of a deepwater well in the Gulf of Mexico.

In addition, the company is a member of the Subsea Well Response Project (SWRP). SWRP's objective is to further develop the industry's capability to contain and shut in subsea well control incidents in different regions of the world.

Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations on pages FS-15 and FS-16 for additional information on environmental matters and their impact on Chevron and on the company's 2012 environmental expenditures. Refer to page FS-15 and Note 24 on page FS-58 for a discussion of environmental remediation provisions and year-end reserves. Refer also to Item 1A. Risk Factors on pages 28 through 30 for a discussion of greenhouse gas regulation and climate change.

Web Site Access to SEC Reports

The company's Internet Web site is www.chevron.com. Information contained on the company's Internet Web site is not part of this Annual Report on Form 10-K. The company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on the company's Web site soon after such reports are filed with or furnished to the Securities and Exchange Commission (SEC). The reports are also available on the SEC's Web site at www.sec.gov.

Item 1A. Risk Factors

Chevron is a global energy company with a diversified business portfolio, a strong balance sheet, and a history of generating sufficient cash to pay dividends and fund capital and exploratory expenditures. Nevertheless, some inherent risks could materially impact the company's financial results of operations or financial condition.

Chevron is exposed to the effects of changing commodity prices: Chevron is primarily in a commodities business that has a history of price volatility. The single largest variable that affects the company's results of operations is the price of crude oil, which can be influenced by general economic conditions, industry inventory levels, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and geopolitical risk. Chevron accepts the risk of changing commodity prices as part of its business planning process. As such, an investment in the company carries significant exposure to fluctuations in global crude oil prices.

During extended periods of historically low prices for crude oil, the company's upstream earnings and capital and exploratory expenditure programs will be negatively affected. Upstream assets may also become impaired. The impact on downstream earnings is dependent upon the supply and demand for refined products and the associated margins on refined product sales.

The scope of Chevron's business will decline if the company does not successfully develop resources: The company is in an extractive business; therefore, if Chevron is not successful in replacing the crude oil and natural gas it produces with good prospects for future production or through acquisitions, the company's business will decline. Creating and maintaining an inventory of projects depends on many factors, including obtaining and renewing rights to explore, develop and produce hydrocarbons; drilling success; ability to bring long-lead-time, capital-intensive projects to completion on budget and on schedule; and efficient and profitable operation of mature properties.

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

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

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

For information concerning some of the litigation in which the company is involved, including information relating to Ecuador matters, see Note 13 to the Consolidated Financial Statements, beginning on FS-40.

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

Political instability and significant changes in the regulatory environment could harm Chevron’s business: The company’s operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates. As has occurred in the past, actions could be taken by governments to increase public ownership of the company’s partially or wholly owned businesses or to impose additional taxes or royalties.

In certain locations, governments have imposed or proposed restrictions on the company’s operations, export and exchange controls, burdensome taxes, and public disclosure requirements that might harm the company’s competitiveness or relations with other governments or third parties. In other countries, political conditions have existed that may threaten the safety of employees and the company’s continued presence in those countries, and internal unrest, acts of violence or strained relations between a government and the company or other governments may adversely affect the company’s operations. Those developments have, at times, significantly affected the company’s related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries. At December 31, 2012, 21 percent of the company’s net proved reserves were located in Kazakhstan. The company also has significant interests in OPEC-member countries, including Angola, Nigeria and Venezuela and in the Partitioned Zone between Saudi Arabia and Kuwait. Twenty-one percent of the company’s net proved reserves, including affiliates, were located in OPEC countries at December 31, 2012.

Regulation of greenhouse gas emissions could increase Chevron’s operational costs and reduce demand for Chevron’s products: Continued political attention to issues concerning climate change, the role of human activity in it, and potential mitigation through regulation could have a material impact on the company’s operations and financial results.

International agreements and national or regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. These and other greenhouse gas emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted in each jurisdiction, the company’s activities in it and market conditions. Greenhouse gas emissions that could be regulated include those arising from the company’s exploration and production of crude oil and natural gas; the upgrading of production from oil sands into synthetic oil; power generation; the conversion of crude oil and natural gas into refined products; the processing, liquefaction and regasification of natural gas; the transportation of crude oil, natural gas and related products and consumers’ or customers’ use of the company’s products. Some of these activities, such as consumers’ and customers’ use of the company’s products, as well as actions taken by the company’s competitors in response to such laws and regulations, are beyond the company’s control.

The effect of regulation on the company's financial performance will depend on a number of factors including, among others, the sectors covered, the greenhouse gas emissions reductions required by law, the extent to which Chevron would be entitled to receive emission allowance allocations or would need to purchase compliance instruments on the open market or through auctions, the price and availability of emission allowances and credits, and the impact of legislation or other regulation on the company's ability to recover the costs incurred through the pricing of the company's products. Material price increases or incentives to conserve or use alternative energy sources could reduce demand for products the company currently sells and adversely affect the company's sales volumes, revenues and margins.

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

Item1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and character of the company's crude oil, natural gas and mining properties and its refining, marketing, transportation and chemicals facilities are described on page 3 under Item 1. Business. Information required by Subpart 1200 of Regulation S-K ("Disclosure by Registrants Engaged in Oil and Gas Producing Activities") is also contained in Item 1 and in Tables I through VII on pages FS-62 through FS-75. Note 12, "Properties, Plant and Equipment," to the company's financial statements is on page FS-40.

Item 3. Legal Proceedings

Ecuador: Information related to Ecuador matters is included in Note 13 to the Consolidated Financial Statements under the heading Ecuador, beginning on page FS-40.

Certain Governmental Proceedings:

In 2011, the California Air Resources Board (CARB) made penalty demands with respect to four notices of violation against Chevron for alleged violations of CARB's fuel blend regulations at certain California terminals and refineries. In November 2011, the statute of limitations expired with respect to two of the notices of violation. On January 28, 2013, settlements were executed, which resolved the remaining two notices of violation. One settlement, with respect to the Richmond Refinery, resulted in the payment of a civil penalty in the amount of $192,500, and the other settlement, relating to

the San Jose and Sacramento terminals, resulted in the payment of a civil penalty in the amount of $205,000.

In July 2009, the Hawaii Department of Health (DOH) alleged that Chevron is obligated to pay stipulated civil penalties exceeding $100,000 in conjunction with commitments Chevron undertook to install and operate certain air emission control equipment at its Hawaii Refinery pursuant to a Clean Air Act settlement with the United States Environmental Protection Agency (EPA) and the DOH. Chevron has disputed many of the allegations.

The EPA indicated that it would assess Chevron's Salt Lake City Refinery a civil penalty for alleged violations of federal requirements and Utah's air quality laws. These alleged violations were the subject of an August 20, 2008, EPA Notice of Violation (NOV) for which no penalty was assessed at the time. It appears that the resolution of this NOV may result in the payment of a civil penalty exceeding $100,000.

The South Coast Air Quality Management District (SCAQMD) issued an NOV to Chevron's Huntington Beach, California, terminal seeking a civil penalty for alleged violations involving the repair of two holes in the roof of a tank at the terminal. On January 24, 2013, Chevron U.S.A. Inc. executed a settlement agreement with the SCAQMD and made payment of $100,000 to resolve the NOV issued to the Huntington Beach terminal.

In September and November 2012, Chevron's Richmond Refinery received from the Bay Area Air Quality Management District (BAAQMD) proposals to resolve 47 alleged NOVs related to air quality regulations. A single settlement agreement has been finalized covering 28 of those NOVs for payment of $145,600 in civil penalties. Resolution of the remaining NOVs is pending and may result in a civil penalty exceeding $100,000.

In April 2012, the South Coast Air Quality Management District (SCAQMD) issued a letter seeking to settle five separate and unrelated NOVs issued to Chevron's El Segundo Refinery in 2011 for alleged violations of various state and local rules relating to air emissions. On January 24, 2013, Chevron U.S.A. Inc. executed a settlement agreement with SCAQMD and made payment of $300,000 to resolve the five NOVs issued to the El Segundo Refinery.

Item 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 C.F.R. § 229.104) is included in Exhibit 95 of this Annual Report on Form 10-K.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities
The information on Chevron's common stock market prices, dividends, principal exchanges on which the stock is traded and number of stockholders of record is contained in the Quarterly Results and Stock Market Data tabulations, on page FS-20.

Chevron Corporation Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[1][2]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program[2]
Oct. 1 – Oct. 31, 2012	3,644,071	$114.16	3,644,045	—
Nov. 1 – Nov. 30, 2012	4,290,367	105.23	4,290,000	—
Dec. 1 – Dec. 31, 2012	3,555,702	107.59	3,555,702	—
Total Oct. 1 – Dec. 31, 2012	11,490,140	$108.79	11,489,747	—

(1) Includes common shares repurchased from company employees for required personal income tax withholdings on the exercise of the stock options and shares delivered or attested to in satisfaction of the exercise price by holders of the employee stock options. The options were issued to and exercised by management under Chevron long-term incentive plans and Unocal stock option plans.

(2) In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits, under which common shares would be acquired by the company through open market purchases (some pursuant to a Rule 10b5-1 plan) at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. As of December 31, 2012, 97,698,628 shares had been acquired under this program for $10 billion.

Item 6. Selected Financial Data
The selected financial data for years 2008 through 2012 are presented on page FS-61.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
The index to Management's Discussion and Analysis of Financial Condition and Results of Operations, Consolidated Financial Statements and Supplementary Data is presented on page FS-1.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk
The company's discussion of interest rate, foreign currency and commodity price market risk is contained in Management's Discussion and Analysis of Financial Condition and Results of Operations — "Financial and Derivative Instruments," beginning on page FS-14 and in Note 9 to the Consolidated Financial Statements, "Financial and Derivative Instruments," beginning on page FS-35.

Item 8. Financial Statements and Supplementary Data
The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1.

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

The company's management has evaluated, with the participation of the Chief Executive Officer and the Chief Financial Officer, the effectiveness of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")) as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the company's disclosure controls and procedures were effective as of December 31, 2012.

(b) Management's Report on Internal Control Over Financial Reporting

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The

company's management, including the Chief Executive Officer and the 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 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of the company's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page FS-22.

(c) Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2012, there were no changes in the company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 22, 2013
The Executive Officers of the Corporation consist of the Chairman of the Board, the Vice Chairman of the Board and such other officers of the Corporation who are members of the Executive Committee.

Name and Age		Current and Prior Positions (up to five years)	Current Areas of Responsibility
J.S. Watson	56	Chairman of the Board and Chief Executive Officer (since 2010) Vice Chairman of the Board (2009) Executive Vice President (2008 to 2009) Vice President and President of Chevron International Exploration and Production Company (2005 through 2007)	Chief Executive Officer
G.L. Kirkland	62	Vice Chairman of the Board and Executive Vice President (since 2010) Executive Vice President (2005 through 2009)	Worldwide Exploration and Production Activities and Global Gas Activities, including Natural Gas Trading
J.R. Blackwell	54	Executive Vice President (since 2011) President of Chevron Asia Pacific Exploration and Production Company (2008 through 2011) Managing Director of Chevron Southern Africa Strategic Business Unit (2003 to 2007)	Technology; Mining; Project Resources Company; Procurement
M.K. Wirth	52	Executive Vice President (since 2006) President of Global Supply and Trading (2004 to 2006)	Worldwide Refining, Marketing, Lubricants, and Supply and Trading Activities, excluding Natural Gas Trading; Chemicals
R.I. Zygocki	55	Executive Vice President (since 2011) Vice President, Policy, Government and Public Affairs (2007 through 2011) Vice President, Health, Environment and Safety (2003 through 2007)	Strategy and Planning; Health, Environment and Safety; Policy, Government and Public Affairs
P.E. Yarrington	56	Vice President and Chief Financial Officer (since 2009) Vice President and Treasurer (2007 through 2008) Vice President, Policy, Government and Public Affairs (2002 to 2007)	Finance
R.H. Pate	50	Vice President and General Counsel (since 2009) Partner and Head of Global Competition Practice of Hunton & Williams LLP, a major U.S. law firm (2005 to 2009)	Law, Governance and Compliance

The information about directors required by Item 401 (a), (d), (e) and (f) of Regulation S-K and contained under the heading “Election of Directors” in the Notice of the 2013 Annual Meeting and 2013 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), in connection with the company's 2013 Annual Meeting of Stockholders (the "2013 Proxy Statement"), is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 405 of Regulation S-K and contained under the heading "Stock Ownership Information — Section 16(a) Beneficial Ownership Reporting Compliance" in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 406 of Regulation S-K

and contained under the heading "Board Operations — Business Conduct and Ethics Code" in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(d)(4) and (5) of Regulation S-K and contained under the heading "Board Operations — Board Committee Membership and Functions" in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

There were no changes to the process by which stockholders may recommend nominees to the Board of Directors during the last fiscal year.

Item 11. Executive Compensation
The information required by Item 402 of Regulation S-K and contained under the headings “Executive Compensation” and “Director Compensation” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(4) of Regulation S-K and contained under the heading “Board Operations — Board Committee Membership and Functions” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(5) of Regulation S-K and contained under the heading “Board Operations — Management Compensation Committee Report” in the 2013 Proxy Statement is incorporated herein by reference into this Annual Report on Form 10-K. Pursuant to the rules and regulations of the SEC under the Exchange Act, the information under such caption incorporated by reference from the 2013 Proxy Statement shall not be deemed to be “soliciting material,” or to be “filed” with the Commission, or subject to Regulation 14A or 14C or the liabilities of Section 18 of the Exchange Act nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters
The information required by Item 403 of Regulation S-K and contained under the heading “Stock Ownership Information — Security Ownership of Certain Beneficial Owners and Management” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 201(d) of Regulation S-K and contained under the heading “Equity Compensation Plan Information” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence
The information required by Item 404 of Regulation S-K and contained under the heading “Board Operations — Transactions with Related Persons” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(a) of Regulation S-K and contained under the heading “Election of Directors — Independence of Directors” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services
The information required by Item 9(e) of Schedule 14A and contained under the heading “Proposal to Ratify the

Appointment of the Independent Registered Public Accounting Firm” in the 2013 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements:

(2) Financial Statement Schedules:

Included on page 36 is Schedule II - Valuation and Qualifying Accounts.

(3) Exhibits:

The Exhibit Index on pages E-1 through E-2 lists the exhibits that are filed as part of this report.

Schedule II — Valuation and Qualifying Accounts
(Millions of Dollars)

	Year Ended December 31		
	2012	2011	2010
Employee Termination Benefits			
Balance at January 1	$63	$145	$13
Additions charged to expense	3	—	235
Payments	(36)	(82)	(103)
Balance at December 31	$30	$63	$145
Allowance for Doubtful Accounts			
Balance at January 1	$167	$239	$293
Additions (reductions) to expense	(4)	4	(13)
Bad debt write-offs	(8)	(76)	(41)
Balance at December 31	$155	$167	$239
Deferred Income Tax Valuation Allowance*			
Balance at January 1	$11,096	$9,185	$7,921
Additions to deferred income tax expense	5,471	2,216	1,454
Reduction of deferred income tax expense	(1,124)	(305)	(190)
Balance at December 31	$15,443	$11,096	$9,185

* See also Note 14 to the Consolidated Financial Statements, beginning on page FS-43.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 22nd day of February, 2013.

Chevron Corporation

By /s/ JOHN S. WATSON
John S. Watson, Chairman of the Board
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 22nd day of February, 2013.

Principal Executive Officers (and Directors)	Directors
/s/JOHN S. WATSON John S. Watson, Chairman of the Board and Chief Executive Officer	LINNET F. DEILY* Linnet F. Deily
/s/GEORGE L. KIRKLAND George L. Kirkland, Vice Chairman of the Board	ROBERT E. DENHAM* Robert E. Denham
	ALICE P. GAST* Alice P. Gast
Principal Financial Officer	ENRIQUE HERNANDEZ, JR.* Enrique Hernandez, Jr.
/s/PATRICIA E. YARRINGTON Patricia E. Yarrington, Vice President and Chief Financial Officer	CHARLES W. MOORMAN* Charles W. Moorman KEVIN W. SHARER* Kevin W. Sharer
Principal Accounting Officer	
/s/MATTHEW J. FOEHR Matthew J. Foehr, Vice President and Comptroller	JOHN G. STUMPF* John G. Stumpf
	RONALD D. SUGAR* Ronald D. Sugar
*By: /s/LYDIA I. BEEBE Lydia I. Beebe,	CARL WARE* Carl Ware

Attorney-in-Fact

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Financial Table of Contents

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

Key Financial Results			
Millions of dollars, except per-share amounts	2012	2011	2010
Net Income Attributable to Chevron Corporation	$26,179	$26,895	$19,024
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
– Basic	$13.42	$13.54	$9.53
– Diluted	$13.32	$13.44	$9.48
Dividends	$3.51	$3.09	$2.84
Sales and Other Operating Revenues	$230,590	$244,371	$198,198
Return on:			
Capital Employed	18.7 %	21.6 %	17.4 %
Stockholders' Equity	20.3 %	23.8 %	19.3 %

Earnings by Major Operating Area			
Millions of dollars	2012	2011	2010
Upstream			
United States	$5,332	$6,512	$4,122
International	18,456	18,274	13,555
Total Upstream	23,788	24,786	17,677
Downstream			
United States	2,048	1,506	1,339
International	2,251	2,085	1,139
Total Downstream	4,299	3,591	2,478
All Other	(1,908)	(1,482)	(1,131)
Net Income Attributable to Chevron Corporation[1,2]	$26,179	$26,895	$19,024
[1] Includes foreign currency effects:	$(454)	$121	$(423)

[2] Also referred to as "earnings" in the discussions that follow.

Refer to the "Results of Operations" section beginning on page FS-6 for a discussion of financial results by major operating area for the three years ended December 31, 2012.

Business Environment and Outlook

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

Earnings of the company depend mostly on the profitability of its upstream and downstream business segments. The biggest factor affecting the results of operations for the company is the level of the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. Seasonality is not a primary driver of changes in the company's quarterly earnings during the year.

To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer attractive financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments.

The company's operations, especially upstream, can also be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. From time to time, certain governments have sought to renegotiate contracts or impose additional costs on the company. Governments may attempt to do so in the future. Civil unrest, acts of violence or strained relations between a government and the company or other governments may impact the company's operations or investments. Those developments have at times significantly affected the company's operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

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 FS-6 for discussions of net gains on asset sales during 2012. 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 price levels 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, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), 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. External factors include not only the general level of inflation, but also 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. Capital and exploratory expenditures and operating expenses can also be affected by damage to production facilities caused by severe weather or civil unrest.

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 $112 per barrel for the full-year 2012, compared to $111 in 2011. As of mid-February 2013, the Brent price was about $118 per barrel. The majority of the company's equity crude production is priced based on the Brent benchmark. The WTI price averaged $94 per barrel for the full-year 2012, compared to $95 in 2011. As of mid-February 2013, the WTI price was about $97 per barrel. WTI traded at a discount to Brent throughout 2012 due to high inventories in the U.S. midcontinent market driven by strong growth in domestic production.

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 supply of heavy crude available versus the demand, which is a function of the capacity of refineries that are

able to process this lower quality feedstock into light products (motor gasoline, jet fuel, aviation gasoline and diesel fuel). During 2012, the differential between U.S. light and heavy crude oil remained below historical norms as light sweet crude oil production in the midcontinent region increased and outbound capacity at Cushing remained constrained. Outside of the U.S., the differential narrowed modestly during 2012 as additional heavy crude oil conversion capacity came on line.

Chevron produces or shares in the production of heavy crude oil in California, Chad, 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 FS-10 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. In the United States, prices at Henry Hub averaged $2.71 per thousand cubic feet (MCF) during 2012, compared with about $4.00 during 2011. As of mid-February 2013, the Henry Hub spot price was about $3.30 per MCF. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America.

Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. 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. International natural gas realizations averaged about $6.00 per MCF during 2012, compared with about $5.40 per MCF during 2011. (See page FS-10 for the company's average natural gas realizations for the U.S. and international regions.)

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The company's worldwide net oil-equivalent production in 2012 averaged 2.610 million barrels per day. About one-fifth of the company's net oil-equivalent production in 2012 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 2012 or 2011. At their December 2012 meeting, members of OPEC supported maintaining the current production quota of 30 million barrels per day, which has been in effect since December 2008.

The company estimates that oil-equivalent production in 2013 will average approximately 2.650 million barrels per day based on an average Brent price of $112 per barrel for the full-year 2012. This estimate is subject to many factors and uncertainties, including quotas 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 project startups or ramp-ups, 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.

Refer to the "Results of Operations" section on pages FS-6 through FS-7 for additional discussion of the company's upstream business.

Refer to Table V beginning on page FS-67 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2010 and each year-end from 2010 through 2012, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2012.

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. No evidence of any coastal or wildlife impacts related to this seep has emerged. On March 14, 2012, the company identified a small, second seep in a different part of the field. As a precautionary measure, the company and its partners decided to temporarily suspend field production and received approval from Brazil's National Petroleum Agency (ANP) to do so. Chevron and its partners are cooperating with the Brazilian authorities. On July 19, 2012, ANP issued its final investigative report on the November 2011 incident. A Brazilian federal district prosecutor filed two civil lawsuits seeking $10.7 billion in damages for

each of the two seeps. The company is not aware of any basis for damages to be awarded in any civil lawsuit. On July 31, 2012, a court presiding over the civil litigation entered a preliminary injunction barring Chevron from conducting oil production and transportation activities in Brazil pending completion of the legal proceedings commenced by the federal district prosecutor and the ongoing proceedings of ANP and the Brazilian environment and natural resources regulatory agency. On September 28, 2012, the injunction was modified to clarify that Chevron may continue its containment and mitigation activities under supervision of ANP. On appeal, on November 27, 2012, the injunction was revoked in its entirety. The federal district prosecutor also filed criminal charges against 11 Chevron employees. Jurisdiction for all three matters was moved from Campos to a court in Rio de Janeiro. On February 19, 2013, the court dismissed the criminal matter, which is subject to appeal by the prosecutor. Chevron has submitted to ANP a plan for restarting limited

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production in the Frade Field. The company’s ultimate exposure related to the incident is not currently determinable, but could be significant to net income in any one period.

The company entered into a nonbinding financing term sheet with Petroboscan, a joint stock company owned 39.2 percent by Chevron, which operates the Boscan Field in Venezuela. When finalized, the financing is expected to occur in stages over a limited drawdown period and is intended to support a specific work program to maintain and increase production to an agreed-upon level. The terms are designed to support cash needs for ongoing operations and new development, as well as distributions to shareholders — including current outstanding obligations. The loan will be repaid from future Petroboscan crude sales. Definitive documents are under negotiation.

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. The company completed a multiyear plan in 2012 to streamline the downstream asset portfolio to concentrate resources and capital on strategic assets. In third quarter 2012, the company completed the sale of its Perth Amboy, New Jersey, refinery, which had been operated as a products terminal in recent years. In 2012, the company completed the sale of its fuels marketing and aviation businesses in eight countries in the Caribbean.

Refer to the “Results of Operations” section on pages FS-7 through FS-8 for additional discussion of the company’s downstream operations.

All Other consists of mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, alternative fuels, and technology companies.

Operating Developments

Key operating developments and other events during 2012 and early 2013 included the following:

Upstream

Australia In October 2012, the company acquired additional interests in the Clio and Acme fields in the Carnarvon Basin in exchange for Chevron's interests in the Browse development. Consolidating interests in the Carnarvon Basin fits strategically with long-term plans to grow the Wheatstone area resource base and creates expansion opportunities for the Wheatstone Project.

In September 2012, the company completed the sale of an equity interest in the Wheatstone Project to Tokyo Electric.

During 2012 and early 2013, the company announced natural gas discoveries at the 47.3 percent-owned and operated Pontus prospect in Block WA-37-L, the 50 percent-owned and operated Satyr prospect in Block WA-374-P, the 50 percent-owned and operated Pinhoe prospect in Block WA-383-P, the 50 percent-owned and operated Arnhem prospect in Block WA-364-P, and the 50 percent-owned and operated Kentish Knock South prospect in Block WA-365-P. These discoveries are expected to contribute to potential expansion opportunities at company-operated LNG facilities.

During 2012, Chevron signed nonbinding Heads of Agreement with Tohoku Electric and Chubu Electric and additional binding agreements with Tokyo Electric for LNG offtake from the Wheatstone Project. To date, more than 80 percent of Chevron's equity LNG from Wheatstone is covered under long-term agreements with customers in Asia.

Angola In early 2013, the company announced it plans to proceed with the development of the Mafumeira Sul Project located in Block 0.

Angola-Republic of the Congo Joint Development Area In third quarter 2012, the company reached a final investment decision on the cross-border development of the deepwater Lianzi Field.

Bangladesh In July 2012, the company reached a final investment decision on the Bibiyana Expansion Project.

Canada In February 2013, Chevron acquired a 50 percent-owned and operated interest in the Kitimat LNG project and proposed Pacific Trail Pipeline, and a 50 percent nonoperated interest in approximately 644,000 acres in the Horn River and Liard Basins.

China In 2012, Chevron entered into an agreement to acquire two exploration blocks in the South China Sea's Pearl River Mouth Basin. Government approval is expected in 2013.

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Kurdistan Region of Iraq In third quarter 2012, Chevron acquired an 80 percent interest and operatorship in the Rovi and Sarta blocks.

Lithuania In October 2012, Chevron acquired a 50 percent interest in a company with exploration interests in a shale gas block.

Morocco In January 2013, the company announced that it had signed agreements to explore three offshore areas.

Nigeria In February 2012, production commenced at the deepwater Usan project.

Sierra Leone In September 2012, the company was awarded a 55 percent interest and operatorship in two deepwater exploration blocks.

Suriname In November 2012, the company acquired a 50 percent interest in two offshore exploration blocks.

Ukraine In second quarter 2012, the company bid successfully for the right to exclusively negotiate a 50 percent interest and operatorship in a shale gas block.

United Kingdom In July 2012, the company initiated front-end engineering and design (FEED) for the deepwater Rosebank project west of the Shetland Islands.

United States In October 2012, the company acquired additional acreage in New Mexico. A major portion of the acreage is located in the Delaware Basin, where the company is already one of the largest leaseholders.

In second quarter 2012, the company successfully bid for additional shelf and deepwater exploration acreage in the central Gulf of Mexico. In fourth quarter 2012, the company submitted high bids for additional deepwater acreage in the western Gulf of Mexico.

In the first quarter 2012, production commenced at the Caesar/Tonga project in the deepwater Gulf of Mexico.

Downstream

Caribbean During 2012, the company completed the sale of its fuels marketing and aviation businesses in eight countries in the Caribbean.

Europe During first quarter 2012, the company completed the sale of its fuels marketing, finished lubricants and aviation businesses in Spain.

Saudi Arabia In October 2012, the company's 50 percent-owned Chevron Phillips Chemical Company LLC announced that its 35 percent-owned Saudi Polymers Company began commercial production at its new petrochemical facility in Al-Jubail.

South Korea During 2012, the company's 50 percent-owned GS Caltex affiliate completed the sale of certain power and other assets.

United States In third quarter 2012, the company completed the sale of its idled Perth Amboy, New Jersey, refinery, which had been operating as a terminal.

In April 2012, the company's 50 percent-owned Chevron Phillips Chemical Company LLC announced the execution of FEED contracts for an ethane cracker at its Cedar Bayou facility in Baytown, Texas, and two polyethylene facilities near its Sweeny facility in Old Ocean, Texas.

Other

Common Stock Dividends The quarterly common stock dividend was increased by 11.1 percent in April 2012 to $0.90 per common share, making 2012 the 25th consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program The company purchased $5.0 billion of its common stock in 2012 under its share repurchase program. The program began in 2010 and has no set term or monetary limits.

Results of Operations

Major Operating Areas The following section presents the results of operations 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 10, beginning on page FS-36, for a discussion of the company's "reportable segments," as defined in accounting standards for segment reporting (Accounting Standards Codification (ASC) 280). This section should also be read in conjunction with the discussion in "Business Environment and Outlook" on pages FS-2 through FS-5.

U.S. Upstream

Millions of dollars	2012	2011	2010
Earnings	$5,332	$6,512	$4,122

U.S. upstream earnings of $5.3 billion in 2012 decreased $1.2 billion from 2011, primarily due to lower natural gas and crude oil realizations of $340 million and $200 million, respectively, lower crude oil production of $240 million, and lower gains on asset sales of $180 million.

U.S. upstream earnings of $6.5 billion in 2011 increased $2.4 billion from 2010. The benefit of higher crude oil realizations increased earnings by $2.8 billion between periods. Partly offsetting this effect were lower net oil-equivalent production, which decreased earnings by about $400 million, and higher operating expenses of $200 million.

The company's average realization for U.S. crude oil and natural gas liquids in 2012 was $95.21 per barrel, compared with $97.51 in 2011 and $71.59 in 2010. The average natural gas realization was $2.64 per thousand cubic feet in 2012, compared with $4.04 and $4.26 in 2011 and 2010, respectively.

Net oil-equivalent production in 2012 averaged 655,000 barrels per day, down 3 percent from 2011 and 7 percent from 2010. Between 2012 and 2011, the decrease in production was associated with normal field declines and an absence of volumes associated with Cook Inlet, Alaska, assets sold in 2011. Partially offsetting this decrease was a ramp-up of projects in the Gulf of Mexico and Marcellus Shale and improved operational performance in the Gulf of Mexico. The net liquids component of oil-equivalent production for 2012 averaged 455,000 barrels per day, down 2 percent from 2011 and 7 percent from 2010. Net natural gas production averaged about 1.2 billion cubic feet per day in 2012, down approximately 6 percent from 2011 and about 8 percent from 2010. Refer to the “Selected Operating Data” table on page FS-10 for a three-year comparative of production volumes in the United States.

International Upstream

Millions of dollars	2012	2011	2010
Earnings*	$18,456	$18,274	$13,555
*Includes foreign currency effects:	$(275)	$211	$(293)

International upstream earnings were $18.5 billion in 2012 compared with $18.3 billion in 2011. The increase was mainly due to a gain of approximate $1.4 billion on an asset exchange in Australia, higher natural gas realizations of about $610 million and a nearly $600 million gain on sale of an equity interest in the Wheatstone Project. Mostly offsetting these effects were lower crude oil volumes of about $1.3 billion and higher exploration expenses of about $430 million. Foreign currency effects decreased earnings by $275 million in 2012, compared with an increase of $211 million a year earlier.

International upstream earnings of $18.3 billion in 2011 increased $4.7 billion from 2010. Higher prices for crude oil increased earnings by $7.1 billion. This benefit was partly offset by higher tax items of about $1.7 billion and higher operating expenses, including fuel, of about $1.0 billion. Foreign currency effects increased earnings by $211 million in 2011, compared with a decrease of $293 million in 2010.

The company’s average realization for international crude oil and natural gas liquids in 2012 was $101.88 per barrel, compared with $101.53 in 2011 and $72.68 in 2010. The average natural gas realization was $5.99 per thousand cubic feet in 2012, compared with $5.39 and $4.64 in 2011 and 2010, respectively.

International net oil-equivalent production of 1.96 million barrels per day in 2012 decreased 2 percent from 2011 and decreased about 5 percent from 2010. New production in Thailand and Nigeria in 2012 was more than offset by normal field declines, the shut-in of the Frade field in Brazil and a major planned turnaround at Tengizchevroil. The decline between 2011 and 2010 was primarily due to price effects on entitlement volumes.

The net liquids component of international oil-equivalent production was about 1.3 million barrels per day in 2012, a decrease of approximately 5 percent from 2011 and a decrease of approximately 9 percent from 2010. International net natural gas production of 3.9 billion cubic feet per day in 2012 was up

6 percent from 2011 and up 4 percent from 2010.

Refer to the “Selected Operating Data” table, on page FS-10, for a three-year comparative of international production volumes.

U.S. Downstream

Millions of dollars	2012	2011	2010
Earnings	$2,048	$1,506	$1,339

U.S. downstream operations earned $2.0 billion in 2012, compared with $1.5 billion in 2011. The increase was mainly due to higher margins on refined product sales of $520 million and higher earnings of $140 million from the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem). These benefits were partly offset by higher operating expenses of $130 million.

Earnings of $1.5 billion in 2011 increased $167 million from 2010. Earnings benefited by $300 million from improved margins on refined products, $200 million from higher earnings from CPChem and $50 million from the absence of 2010 charges related to employee reductions. These benefits were partly offset by the absence of a $400 million gain on the sale of the company's ownership interest in the Colonial Pipeline Company recognized in 2010.

Refined product sales of 1.21 million barrels per day in 2012 declined 4 percent, mainly reflecting lower gasoline and fuel oil sales. Sales volumes of refined products were 1.26 million barrels per day in 2011, a decrease of 7 percent from 2010. The decline was mainly in gasoline, gas oil and kerosene sales. U.S. branded gasoline sales of 516,000 barrels per day in 2012 were essentially flat from 2011 and declined approximately 10 percent from 2010. The decline in 2012 and

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2011 from 2010 was primarily due to weaker demand and previously completed exits from selected eastern U.S. retail markets.

Refer to the “Selected Operating Data” table on page FS-10 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

Millions of dollars	2012	2011	2010
Earnings*	$2,251	$2,085	$1,139
*Includes foreign currency effects:	$(173)	$(65)	$(135)

International downstream earned $2.3 billion in 2012, compared with $2.1 billion in 2011. Earnings increased due to a favorable change in effects on derivative instruments of $190 million and higher margins on refined product sales of $100 million. Foreign currency effects decreased earnings by $173 million in 2012, compared with a decrease of $65 million a year earlier.

Earnings of $2.1 billion in 2011 increased $946 million from 2010. Gains on asset sales benefited earnings by $700 million, primarily from the sale of the Pembroke Refinery and related marketing assets in the United Kingdom and Ireland. Also contributing to earnings were improved margins of $200 million and the absence of 2010 charges of $90 million related to employee reductions. These benefits were partly offset by an unfavorable change in effects on derivative instruments of about $180 million. Foreign currency effects decreased earnings by $65 million in 2011, compared with a decrease of $135 million in 2010.

Total refined product sales of 1.55 million barrels per day in 2012 declined 8 percent, primarily related to the third quarter 2011 sale of the company’s refining and marketing assets in the United Kingdom and Ireland. Excluding the impact of 2011 asset sales, sales volumes were flat between the comparative periods. International refined product sales volumes of 1.69 million barrels per day in 2011 were 4 percent lower than in 2010, primarily due to the sale of the company's refining and marketing assets in the United Kingdom and Ireland. Excluding the impact of 2011 asset sales, sales volumes were up 3 percent between the comparative periods.

Refer to the “Selected Operating Data” table, on page FS-10, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars	2012	2011	2010
Net charges*	$(1,908)	$(1,482)	$(1,131)
*Includes foreign currency effects:	$(6)	$(25)	$5

All Other includes mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, alternative fuels, and technology companies.

Net charges in 2012 increased 426 million from 2011, mainly due to higher environmental reserve additions, corporate tax items and other corporate charges, partially offset by lower employee compensation and benefits expenses.

Net charges in 2011 increased $351 million from 2010, mainly due to higher expenses for employee compensation and benefits and higher net corporate tax expenses.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	2012	2011	2010
Sales and other operating revenues	$230,590	$244,371	$198,198

Sales and other operating revenues decreased in 2012 mainly due to the 2011 sale of the company's refining and marketing assets in the United Kingdom and Ireland, and lower crude oil volumes. Higher 2011 prices for crude oil and refined products resulted in increased sales and other operating revenues compared with 2010.

Millions of dollars	2012	2011	2010
Income from equity affiliates	$6,889	$7,363	$5,637

Income from equity affiliates decreased in 2012 from 2011 mainly due to lower upstream-related earnings from Tengizchevroil in Kazakhstan as a result of lower crude oil production, and higher operating expenses at Angola LNG Limited and Petropiar in Venezuela. Downstream-related earnings were higher between comparative periods, primarily due to higher margins at CPChem.

Income from equity affiliates increased in 2011 from 2010 mainly due to higher upstream-related earnings from Tengizchevroil as a result of higher prices for crude oil. Downstream-related earnings were also higher between the comparative periods, primarily due to higher earnings from CPChem as a result of higher margins on sales of commodity chemicals.

Refer to Note 11, beginning on page FS-38, for a discussion of Chevron's investments in affiliated companies.

Millions of dollars	2012	2011	2010
Other income	$4,430	$1,972	$1,093

Other income of $4.4 billion in 2012 included net gains from asset sales of approximately $4.2 billion. Other income in both 2011 and 2010 included net gains from asset sales of $1.5 billion and $1.1 billion, respectively. Interest income was approximately $166 million in 2012, $145 million in 2011 and $120 million in 2010. Foreign currency effects decreased other income by $207 million in 2012, while increasing other income by $103 million in 2011 and decreasing other income by $251 million in 2010.

Millions of dollars	2012	2011	2010
Purchased crude oil and products	$140,766	$149,923	$116,467

Crude oil and product purchases of $140.8 billion were down in 2012 mainly due to the 2011 sale of the company's refining and marketing assets in the United Kingdom and Ireland and lower natural gas prices. Crude oil and product purchases in 2011 increased by $33.5 billion from the prior year due to higher prices for crude oil, natural gas and refined products.

Millions of dollars	2012	2011	2010
Operating, selling, general and administrative expenses	$27,294	$26,394	$23,955

Operating, selling, general and administrative expenses increased $900 million between 2012 and 2011 mainly due to higher contract labor and professional services of $590 million, and higher employee compensation and benefits of $280 million.

Operating, selling, general and administrative expenses increased $2.4 billion between 2011 and 2010. This increase was primarily related to higher fuel expenses of $1.5 billion and higher employee compensation and benefits of $700 million. In part, increased fuel purchases in 2011 reflected a new commercial arrangement that replaced a prior product exchange agreement for upstream operations in Indonesia.

Millions of dollars	2012	2011	2010
Exploration expense	$1,728	$1,216	$1,147

Exploration expenses in 2012 increased from 2011 mainly due to higher geological and geophysical costs and well write-offs.

Exploration expenses in 2011 increased from 2010 mainly due to higher geological and geophysical costs, partly offset by lower well write-offs.

Millions of dollars	2012	2011	2010
Depreciation, depletion and amortization	$13,413	$12,911	$13,063

The increase in 2012 from 2011 was mainly due to higher depreciation rates for certain oil and gas producing fields, partially offset by lower production levels. The decrease in 2011 from 2010 mainly reflected lower production levels and the 2011 sale of the Pembroke Refinery, partially offset by higher depreciation rates for certain oil and gas producing fields.

Millions of dollars	2012	2011	2010
Taxes other than on income	$12,376	$15,628	$18,191

Taxes other than on income decreased in 2012 from 2011 primarily due to lower import duties in the United Kingdom reflecting the sale of the company's refining and marketing assets in the United Kingdom and Ireland in 2011. Partially offsetting the decrease were excise taxes associated with consolidation of Star Petroleum Refining Company beginning June 2012. Taxes other than on income decreased in 2011 from 2010 primarily due to lower import duties in the United Kingdom reflecting the 2011 sale of the Pembroke Refinery and other downstream assets, partly offset by higher excise taxes in the company's South Africa downstream operations.

Millions of dollars	2012	2011	2010
Interest and debt expense	$—	$—	$50

Total interest and debt expenses were fully capitalized in 2012 and 2011.

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Millions of dollars	2012	2011	2010
Income tax expense	$19,996	$20,626	$12,919

Effective income tax rates were 43 percent in 2012, 43 percent in 2011 and 40 percent in 2010. The rate was unchanged between 2012 and 2011. The impact of lower effective tax rates in international upstream operations were offset by foreign currency remeasurement impacts between periods. For international upstream, the lower effective tax rates in the current period were driven primarily by the effects of asset sales, one-time tax benefits and reduced withholding taxes, which were partially offset by a lower utilization of tax credits during the year. The rate was higher in 2011 than in 2010 primarily due to higher effective tax rates in certain international upstream jurisdictions. The higher international upstream effective tax rates were driven primarily by lower utilization of non-U.S. tax credits in 2011 and the effect of changes in income tax rates between periods, which were partially offset by foreign currency remeasurement impacts.

Selected Operating Data[1,2]

	2012	2011	2010
U.S. Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	455	465	489
Net Natural Gas Production (MMCFPD)[3]	1,203	1,279	1,314
Net Oil-Equivalent Production (MBOEPD)	655	678	708
Sales of Natural Gas (MMCFPD)	5,470	5,836	5,932
Sales of Natural Gas Liquids (MBPD)	16	15	22
Revenues From Net Production			
Liquids ($/Bbl)	$95.21	$97.51	$71.59
Natural Gas ($/MCF)	$2.64	$4.04	$4.26
International Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)[4]	1,309	1,384	1,434
Net Natural Gas Production (MMCFPD)[3]	3,871	3,662	3,726
Net Oil-Equivalent Production (MBOEPD)			
Production (MBOEPD)[4]	1,955	1,995	2,055
Sales of Natural Gas (MMCFPD)	4,315	4,361	4,493
Sales of Natural Gas Liquids (MBPD)	24	24	27
Revenues From Liftings			
Liquids ($/Bbl)	$101.88	$101.53	$72.68
Natural Gas ($/MCF)	$5.99	$5.39	$4.64
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD) [4]			
United States	655	678	708
International	1,955	1,995	2,055
Total	2,610	2,673	2,763
U.S. Downstream			
Gasoline Sales (MBPD)[5]	624	649	700
Other Refined Product Sales (MBPD)	587	608	649
Total Refined Product Sales (MBPD)	1,211	1,257	1,349
Sales of Natural Gas Liquids (MBPD)	141	146	139

Refinery Input (MBPD)	833	854	890
International Downstream			
Gasoline Sales (MBPD)[5]	412	447	521
Other Refined Product Sales (MBPD)	1,142	1,245	1,243
Total Refined Product Sales (MBPD)[6]	1,554	1,692	1,764
Sales of Natural Gas Liquids (MBPD)	64	63	78
Refinery Input (MBPD)[7]	869	933	1,004

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):

United States	63	69	62
International	523	513	475

4 Includes: Canada – synthetic oil 43 40 24
Venezuela affiliate – synthetic oil 17 32 28

5 Includes branded and unbranded gasoline.

6 Includes sales of affiliates (MBPD): 522 556 562

7 As of June 2012, Star Petroleum Refining Company crude-input volumes are reported on a 100 percent consolidated basis. Prior to June 2012, crude-input volumes reflect a 64 percent equity interest.

Liquidity and Capital Resources

Cash, cash equivalents, time deposits and marketable securities Total balances were $21.9 billion and $20.1 billion at December 31, 2012 and 2011, respectively. Cash provided by operating activities in 2012 was $38.8 billion, compared with $41.1 billion in 2011 and $31.4 billion in 2010. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.2 billion, $1.5 billion and $1.4 billion in 2012, 2011 and 2010, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.7 billion in 2012, $3.5 billion in 2011, and $2.0 billion in 2010.

Restricted cash of $1.5 billion and $1.2 billion associated with tax payments, upstream abandonment activities, funds held in escrow for an asset acquisition and capital investment projects at December 31, 2012 and 2011, respectively, was invested in short-term marketable securities and recorded as "Deferred charges and other assets" on the Consolidated Balance Sheet.

Dividends Dividends paid to common stockholders were $6.8 billion in 2012, $6.1 billion in 2011 and $5.7 billion in 2010. In April 2012, the company increased its quarterly dividend by 11.1 percent to 90 cents per common share.

Debt and capital lease obligations Total debt and capital lease obligations were $12.2 billion at December 31, 2012, up from $10.2 billion at year-end 2011.

The $2.0 billion increase in total debt and capital lease obligations during 2012 included the net effect of a $4 billion bond issuance and the early redemption of a $2 billion bond due in March 2014. 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 $6.0 billion at December 31, 2012, compared with $5.9 billion at year-end 2011. Of these amounts, $5.9 billion and $5.6 billion were reclassified to long-term at the end of each period, respectively. At year-end 2012, settlement of these obligations was not expected to require the use of working capital in 2013, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

At December 31, 2012, the company had $6.0 billion in committed credit facilities with various major banks, expiring in December 2016, which enable the refinancing of short-term obligations on a long-term basis. 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, 2012. In addition, in November 2012, the company filed with the Securities and Exchange Commission a new registration statement that expires in November 2015. This registration statement is for an unspecified amount of nonconvertible debt securities issued or guaranteed by

the company.

The major debt rating agencies routinely evaluate the company's debt, and the company's cost of borrowing can increase or decrease depending on these debt ratings. The company has outstanding public bonds issued by Chevron Corporation, Chevron Corporation Profit Sharing/Savings Plan Trust Fund and Texaco Capital Inc. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard & Poor's Corporation and 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. The company also can modify capital spending plans during any extended periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals to provide flexibility to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

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 expects to repurchase between $500 million and $2 billion of its common shares per quarter, at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. During 2012, the company purchased 46.6 million common shares for $5.0 billion. From the inception of the program through

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Capital and Exploratory Expenditures

	2012			2011			2010		
Millions of dollars	U.S.	Int’l.	Total	U.S.	Int’l.	Total	U.S.	Int’l.	Total
Upstream[1]	$8,531	$21,913	$30,444	$8,318	$17,554	$25,872	$3,450	$15,454	$18,904
Downstream	1,913	1,259	3,172	1,461	1,150	2,611	1,456	1,096	2,552
All Other	602	11	613	575	8	583	286	13	299
Total	$11,046	$23,183	$34,229	$10,354	$18,712	$29,066	$5,192	$16,563	$21,755
Total, Excluding Equity in Affiliates	$10,738	$21,374	$32,112	$10,077	$17,294	$27,371	$4,934	$15,433	$20,367

[1] Excludes the acquisition of Atlas Energy, Inc., in 2011.

2012, the company had purchased 97.7 million shares for $10.0 billion.

Capital and exploratory expenditures Total expenditures for 2012 were $34.2 billion, including $2.1 billion for the company’s share of equity-affiliate expenditures. In 2011 and 2010, expenditures were $29.1 billion and $21.8 billion, respectively, including the company’s share of affiliates’ expenditures of $1.7 billion and $1.4 billion, respectively.

Of the $34.2 billion of expenditures in 2012, 89 percent, or $30.4 billion, was related to upstream activities. Approximately 89 percent and 87 percent were expended for upstream operations in 2011 and 2010. International upstream accounted for about 72 percent of the worldwide upstream investment in 2012, about 68 percent in 2011 and about 82 percent in 2010. These amounts exclude the acquisition of Atlas Energy, Inc., in 2011.

The company estimates that 2013 capital and exploratory expenditures will be $36.7 billion, including $3.3 billion of

spending by affiliates. Approximately 90 percent of the total, or $33 billion, is budgeted for exploration and production activities. Approximately $25.5 billion, or 77 percent, of this amount is for projects outside the United States. Spending in 2013 is primarily focused on major development projects in Angola, Australia, Brazil, Canada, China, Kazakhstan, Nigeria, Republic of Congo, Russia, the United Kingdom and the U.S. Gulf of Mexico. Also included is funding for enhancing recovery and mitigating natural field declines for currently-producing assets, and for focused exploration and appraisal activities.

Worldwide downstream spending in 2013 is estimated at $2.7 billion, with about $1.4 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States, expansion of additives production capacity in Singapore and chemicals projects in the United States.

Investments in technology companies, power generation and other corporate businesses in 2013 are budgeted at $1 billion.

Noncontrolling interests The company had noncontrolling interests of $1,308 million and $799 million at December 31, 2012 and 2011, respectively. Distributions to noncontrolling interests totaled $41 million and $71 million in 2012 and 2011, respectively.

Pension Obligations Information related to pension plan contributions is included on page FS-54 in Note 20 to the Consolidated Financial Statements under the heading “Cash Contributions and Benefit Payments.” Refer also to the discussion of pension accounting in “Critical Accounting Estimates and Assumptions,” beginning on page FS-16.

Financial Ratios

Financial Ratios

	At December 31					
	2012		2011		2010	
Current Ratio	1.6		1.6		1.7	
Interest Coverage Ratio	191.3		165.4		101.7	
Debt Ratio	8.2	%	7.7	%	9.8	%

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 2012, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $9.3 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 2012 was higher than 2011 and 2010 due to lower before-tax interest costs.

Debt Ratio – total debt as a percentage of total debt plus Chevron Corporation Stockholders' Equity, which indicates the company's leverage. The increase between 2012 and 2011 was due to higher debt, partially offset by a higher Chevron Corporation stockholders' equity balance. The decrease between 2011 and 2010 was due to a higher Chevron Corporation stockholders' equity balance.

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

Direct Guarantees

Millions of dollars	Commitment Expiration by Period				
			2014–	2016–	After
	Total	2013	2015	2017	2017
Guarantee of non- consolidated affiliate or joint-venture obligations	$562	$38	$76	$76	$372

The company's guarantee of $562 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 15-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 FS-56 in Note 22 to the Consolidated Financial Statements under the heading "Indemnifications."

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay

Agreements The company and its subsidiaries have certain other 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: 2013 – $3.7 billion; 2014 – $3.9 billion; 2015 – $4.1 billion; 2016 – $2.4 billion; 2017 – $1.8 billion; 2018 and after – $6.5 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3.6 billion in 2012, $6.6 billion in 2011 and $6.5 billion in 2010.

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

Contractual Obligations[1]

Millions of dollars	Payments Due by Period				
	Total	2013	2014–2015	2016–2017	After 2017
On Balance Sheet:[2]					
Short-Term Debt[3]	$127	$127	$—	$—	$—
Long-Term Debt[3]	11,966	—	5,923	2,000	4,043
Noncancelable Capital Lease Obligations	189	45	60	25	59
Interest	1,983	210	408	402	963
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	3,548	727	1,276	929	616
Throughput and Take-or-Pay Agreements[4]	17,164	2,705	5,480	2,904	6,075
Other Unconditional Purchase Obligations[4]	5,285	1,003	2,470	1,342	470

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 20 beginning on page FS-49.

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 these liabilities may become payable. The company does not expect settlement of such liabilities will have a material effect on its consolidated financial position or liquidity in any single period.

3 $5.9 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2014–2015 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.

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Financial and Derivative Instruments
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 2012 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 2012.

The company’s market exposure positions are monitored and managed on a daily basis by an internal Risk Control group in accordance with the company’s risk management policies, which have been approved by the Audit Committee of the company’s Board of Directors.

The derivative commodity instruments used in the company’s risk management and trading activities consist mainly of futures, options and swap contracts traded on the New York Mercantile Exchange and on electronic platforms of the Inter-Continental Exchange and Chicago Mercantile Exchange. In addition, crude oil, natural gas and refined product swap contracts and option contracts are entered into principally with major financial institutions and other oil and gas companies in the “over-the-counter” markets.

Derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet in accordance with accounting standards for derivatives (ASC 815), 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 2012 was a quarterly average decrease of $31 million in total assets and a quarterly average increase of $12 million in total liabilities.

The company uses a Value-at-Risk (VaR) model to estimate the potential loss in fair value on a single day from the effect of adverse changes in market conditions on derivative commodity instruments held or issued. VaR is the maximum projected loss not to be exceeded within a given probability or confidence level over a given period of time. The company’s VaR model uses the Monte Carlo simulation method that involves generating hypothetical scenarios from the specified probability distributions and constructing a full distribution of a portfolio’s potential values.

The VaR model utilizes an exponentially weighted moving average for computing historical volatilities and correlations, a 95 percent confidence level, and a one-day holding period. That is,

the company’s 95 percent, one-day VaR corresponds to the unrealized loss in portfolio value that would not be exceeded on average more than one in every 20 trading days, if the portfolio were held constant for one day.

The one-day holding period is based on the assumption that market-risk positions can be liquidated or hedged within one day. For hedging and risk management, the company uses conventional exchange-traded instruments such as futures and options as well as non-exchange-traded swaps, most of which can be liquidated or hedged effectively within one day. The following table presents the 95 percent/one-day VaR for each of the company’s primary risk exposures in the area of derivative commodity instruments at December 31, 2012 and 2011.

Millions of dollars	2012	2011
Crude Oil	$3	$22
Natural Gas	3	4
Refined Products	12	11

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, 2012.

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 2012, 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 11 of the Consolidated Financial Statements, page FS-39, 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 FS-40 in Note 13 to the Consolidated Financial Statements under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 13 to the Consolidated Financial Statements under the heading "Ecuador," beginning on page FS-40.

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	2012	2011	2010
Balance at January 1	$1,404	$1,507	$1,700
Net Additions	428	343	220
Expenditures	(429)	(446)	(413)
Balance at December 31	$1,403	$1,404	$1,507

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 $13.3 billion for asset retirement obligations at year-end 2012 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 2012 environmental expenditures. Refer to Note 22 on pages FS-56 through FS-57 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 23 on page FS-58 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 18 to the Consolidated Financial Statements, Accounting for Suspended Wells, beginning on page FS-47.

Income Taxes Information related to income tax contingencies is included on pages FS-43 through FS-45 in Note 14 and pages FS-55 through FS-56 in Note 22 to the Consolidated Financial Statements under the heading "Income Taxes."

The American Taxpayer Relief Act of 2012 (the Act) was signed into U.S. law on January 2, 2013. Several tax provisions that expired at the end of 2011 were extended retroactive to January 1, 2012, including the research and development credit and certain rules for controlled foreign corporations. There were no impacts from the Act included in Chevron's 2012 financial statements and the company does not expect the impacts of the Act to have a material effect on its results of operations, consolidated financial position or liquidity in any future reporting period.

Other Contingencies Information related to other contingencies is included on page FS-57 in Note 22 to the Consolidated Financial Statements under the heading "Other Contingencies."

Environmental Matters

Virtually all aspects of the businesses in which the company engages are subject to various international, federal, state and local environmental, health and safety laws, regulations and market-based programs. These regulatory requirements continue 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. Regulations intended to address concerns about greenhouse gas emissions and global climate change also continue to evolve and include those at the international or multinational (such as the mechanisms under the Kyoto Protocol and the European Union's Emissions Trading System), national (such as the U.S. Environmental Protection Agency's emission standards and renewable transportation fuel content requirements or domestic market-based programs such as those in effect in Australia and New Zealand), and state or regional (such as California's Global Warming Solutions Act) levels.

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

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. In addition to the costs for environmental protection associated with its ongoing operations and products, 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 2012 at approximately $2.8 billion for its consolidated companies. Included in these expenditures were approximately $1.1 billion of environmental capital expenditures and $1.7 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 2013, total worldwide environmental capital expenditures are estimated at $1.2 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. All 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:

Pension and Other Postretirement Benefit Plans The determination of pension plan obligations and expense 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. For other postretirement benefit (OPEB) plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining OPEB obligations and expense are the discount rate and the assumed health care cost-trend rates.

Note 20, beginning on page FS-49, includes information on the funded status of the company’s pension and OPEB plans at the end of 2012 and 2011; the components of pension and OPEB expense for the three years ended December 31, 2012; and the underlying assumptions for those periods.

Pension and OPEB expense is reported on the Consolidated Statement of Income as “Operating expenses” or “Selling, general and administrative expenses” and applies to all business segments. The year-end 2012 and 2011 funded status, measured as the difference between plan assets and obligations, of each of the company’s pension and OPEB plans is recognized on the Consolidated Balance Sheet. The differences related to overfunded pension plans are reported as a long-term asset in “Deferred charges and other assets.” The differences associated with underfunded or unfunded pension and OPEB plans are reported as “Accrued liabilities” or “Reserves for employee benefit plans.” Amounts yet to be recognized as components of pension or OPEB expense are reported in "Accumulated other comprehensive loss."

To estimate the long-term rate of return on pension assets, the company uses a process that incorporates actual historical asset-class returns and an assessment of expected future performance and takes into consideration external actuarial advice and asset-class factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies. For 2012, the company used an expected long-term rate of return of 7.5 percent for U.S. pension plan assets, which account for 70 percent of the company's pension plan assets. In 2011 and 2010, the company used a long-term rate of return of 7.8 percent for this plan. For the 10 years ending December 31, 2012, actual asset returns averaged 7.1 percent for this plan. The actual return for 2012 was more than 7.5 percent and was associated with a broad recovery in the financial markets during the year. Additionally, with the exception of two other years within this 10-year period, actual asset returns for this plan equaled or exceeded 7.5 percent.

The year-end market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market value in the preceding three months. Management considers the three-month 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.

The discount rate assumptions used to determine the U.S. and international pension and postretirement benefit plan obligations and expense reflect the at which benefits could be effectively settled and is 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, 2012, the company used a 3.6 percent discount rate for the U.S. pension plans and 3.9 percent for the main U.S. OPEB plan. The discount rates at the end of 2011 and 2010 were 3.8 and 4.0 percent and 4.8 and 5.0 percent for the U.S. pension plans and the main U.S. OPEB plans, respectively.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2012 was $1.3 billion. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the company’s primary U.S. pension plan would have reduced total pension plan expense for 2012 by approximately $80 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 62 percent of the companywide pension obligation, would have reduced total pension plan expense for 2012 by approximately $165 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan reported on the Consolidated Balance Sheet. The aggregate funded status recognized on the Consolidated Balance Sheet at December 31, 2012, was a net liability of approximately $5.9 billion. 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 would have reduced the plan obligation by approximately $335 million, which would have decreased the plan’s underfunded status from approximately $2.6 billion to $2.2 billion. Other plans would be less underfunded as discount rates increase. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world’s financial markets.

In 2012, the company’s pension plan contributions were $1.2 billion (including $844 million to the U.S. plans). In 2013, the company estimates contributions will be approximately $1.0 billion. Actual contribution amounts are dependent upon investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

For the company’s OPEB plans, expense for 2012 was $172 million, and the total liability, which reflected the unfunded status of the plans at the end of 2012, was $3.8 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2012, a 1 percent increase in the discount rate for the company’s primary U.S. OPEB plan, which accounted for about 82 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $17 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 83 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2012 by approximately $80 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 7.5 percent in 2013 and gradually drop to 4.5 percent for 2025 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2012, a 1 percent increase in the rates for the main U.S. OPEB plan, would have increased OPEB expense by $15 million.

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are not included in benefit plan costs in the year the difference occurs. Instead, the differences are included in actuarial gain/loss and unamortized amounts have been reflected in “Accumulated other comprehensive loss” on the Consolidated Balance Sheet. Refer to Note 20, beginning on page FS-49, for information on the $9.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2012; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2013.

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 and economic conditions.

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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 - Proved reserves are used in amortizing capitalized costs related to oil and gas producing activities on the unit-of-production (UOP) method. Capitalized exploratory drilling and development costs are depreciated on a UOP basis using proved developed reserves. Acquisition costs of proved properties are amortized on a UOP basis using total proved reserves. During 2012, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for oil and gas properties was $10.7 billion, and proved developed reserves at the beginning of 2012 were 4.8 billion barrels. 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 2012 would have increased by approximately $540 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. In assessing whether the property is impaired, the fair value of the property must be determined. Frequently, a discounted cash flow methodology is the best estimate of fair value. 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 FS-67, for the changes in proved reserve estimates for the three years ending December 31, 2012, and to Table VII, “Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves” on page FS-75 for estimates of proved reserve values for each of the three years ended December 31, 2012.

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 FS-28, 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. Such indicators include changes in the company’s business plans, changes in commodity prices and, for crude oil and natural gas properties, significant downward revisions of estimated proved reserve quantities. 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 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 8 beginning on page FS-33 and to the section on Properties, Plant and Equipment in Note 1, Summary of Significant Accounting Policies, beginning on page FS-28.

No material individual impairments of PP&E or Investments were recorded for the three years ending December 31, 2012. 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.

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 such a decline is deemed to be other than temporary, an impairment charge is recorded to the income statement for the difference between the investment's carrying value and its estimated fair value at the time.

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. Differing assumptions could affect whether an investment is impaired in any period or the amount of the impairment, and are not subject to sensitivity analysis.

From time to time, the company performs impairment reviews and determines 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. 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.

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 2012 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 23 on page FS-58 for additional discussions on asset retirement obligations.

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 14 beginning on page FS-43. 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, 2012.

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 17, on page FS-47 in the Notes to Consolidated Financial Statements, for information regarding new accounting standards.

Quarterly Results and Stock Market Data
Unaudited

	2012				2011			
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]	$56,254	$55,660	$59,780	$58,896	$58,027	$61,261	$66,671	58,412
Income from equity affiliates	1,815	1,274	2,091	1,709	1,567	2,227	1,882	$1,687
Other income	2,483	1,110	737	100	391	944	395	242
Total Revenues and Other Income	60,552	58,044	62,608	60,705	59,985	64,432	68,948	60,341
Costs and Other Deductions								
Purchased crude oil and products	33,959	33,982	36,772	36,053	36,363	37,600	40,759	35,201
Operating expenses	6,273	5,694	5,420	5,183	5,948	5,378	5,260	5,063
Selling, general and administrative expenses	1,182	1,352	1,250	940	1,330	1,115	1,200	1,100
Exploration expenses	357	475	493	403	386	240	422	168
Depreciation, depletion and amortization	3,554	3,370	3,284	3,205	3,313	3,215	3,257	3,126
Taxes other than on income[1]	3,251	3,239	3,034	2,852	2,680	3,544	4,843	4,561
Interest and debt expense	—	—	—	—	–	–	–	–
Total Costs and Other Deductions	48,576	48,112	50,253	48,636	50,020	51,092	55,741	49,219
Income Before Income Tax Expense	11,976	9,932	12,355	12,069	9,965	13,340	13,207	11,122
Income Tax Expense	4,679	4,624	5,123	5,570	4,813	5,483	5,447	4,883
Net Income	$7,297	$5,308	$7,232	$6,499	$5,152	$7,857	$7,760	$6,239
Less: Net income attributable to noncontrolling interests	52	55	22	28	29	28	28	28
Net Income Attributable to Chevron Corporation	$7,245	$5,253	$7,210	$6,471	$5,123	$7,829	$7,732	$6,211
Per Share of Common Stock								
Net Income Attributable to Chevron Corporation								
– Basic	$3.73	$2.71	$3.68	$3.30	$2.61	$3.94	$3.88	$3.11
– Diluted	$3.70	$2.69	$3.66	$3.27	$2.58	$3.92	$3.85	$3.09
Dividends	$0.90	$0.90	$0.90	$0.81	$0.81	$0.78	$0.78	$0.72
Common Stock Price Range – High[2]	$118.38	$118.53	$108.79	$112.28	$110.01	$109.75	$109.94	$109.65
– Low[2]	$100.66	$103.29	$95.73	$102.08	$86.68	$87.30	$97.00	$90.12
[1] Includes excise, value-added and similar taxes:	$2,131	$2,163	$1,929	$1,787	$1,713	$1,974	$2,264	$2,134

[2] Intraday price.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 11, 2013, stockholders of record numbered approximately 168,000. 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 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 judgment.

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.

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 such term is defined in Exchange Act Rule 13a-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 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of the company's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

John S. Watson	Patricia E. Yarrington	Matthew J. Foehr
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 22, 2013

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 sheet 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, 2012, and December 31, 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, 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, on the financial statement schedule, 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.

San Francisco, California

February 22, 2013

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

	Year ended December 31		
	2012	2011	2010
Revenues and Other Income			
Sales and other operating revenues*	$230,590	$244,371	$198,198
Income from equity affiliates	6,889	7,363	5,637
Other income	4,430	1,972	1,093
Total Revenues and Other Income	241,909	253,706	204,928
Costs and Other Deductions			
Purchased crude oil and products	140,766	149,923	116,467
Operating expenses	22,570	21,649	19,188
Selling, general and administrative expenses	4,724	4,745	4,767
Exploration expenses	1,728	1,216	1,147
Depreciation, depletion and amortization	13,413	12,911	13,063
Taxes other than on income*	12,376	15,628	18,191
Interest and debt expense	—	—	50
Total Costs and Other Deductions	195,577	206,072	172,873
Income Before Income Tax Expense	46,332	47,634	32,055
Income Tax Expense	19,996	20,626	12,919
Net Income	26,336	27,008	19,136
Less: Net income attributable to noncontrolling interests	157	113	112
Net Income Attributable to Chevron Corporation	$26,179	$26,895	$19,024
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
– Basic	$13.42	$13.54	$9.53
– Diluted	$13.32	$13.44	$9.48
*Includes excise, value-added and similar taxes.	$8,010	$8,085	$8,591

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2012	2011	2010
Net Income	$26,336	$27,008	$19,136
Currency translation adjustment			
Unrealized net change arising during period	23	17	6
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	1	(11)	(4)
Derivatives			
Net derivatives gain on hedge transactions	20	20	25
Reclassification to net income of net realized (gain) loss	(14)	9	5
Income taxes on derivatives transactions	(3)	(10)	(10)
Total	3	19	20
Defined benefit plans			
Actuarial loss			