CHEVRON CORP
Form 10-K
February 23, 2012

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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, 2011**
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 $205,986,778,815 (As of June 30, 2011)

Number of Shares of Common Stock outstanding as of February 13, 2012 1,976,966,530

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2012 Annual Meeting and 2012 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company s 2012 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, proje believes, seeks, schedules, estimates, budgets and similar expressions are intended to identify such forward-look statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some 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 chemical 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 net 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 under 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 29 through 31 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.

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PART I

Item 1. Business

(a) 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 operations, 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, 2011, Chevron had approximately 61,000 employees (including about 3,800 service station employees). Approximately 30,000 employees (including about 3,500 service station employees), or 49 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 also 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.

* 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 it does 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.

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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.

(b) Description of Business and Properties

The upstream and downstream activities of the company and its equity affiliates are widely dispersed geographically, with operations 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, 2011, and assets as of the end of 2011 and 2010 for the United States and the company s international geographic areas are in Note 11 to the Consolidated Financial Statements beginning on page FS-37. Similar comparative data for the company s investments in and income from equity affiliates and property, plant and equipment are in Notes 12 and 13 on pages FS-39 through FS-41.

Capital and Exploratory Expenditures

Total expenditures for 2011 were $29.1 billion, including $1.7 billion for the company s share of equity-affiliate expenditures. In 2010 and 2009, expenditures were $21.8 billion and $22.2 billion, respectively, including the company s share of affiliates expenditures of $1.4 billion in 2010 and $1.6 billion in 2009.

Of the $29.1 billion in expenditures for 2011, 89 percent, or $25.9 billion, was related to upstream activities. Approximately 87 and 80 percent was expended for upstream operations in 2010 and 2009, respectively. International upstream accounted for about 68 percent of the worldwide upstream investment in 2011, about 82 percent in 2010 and about 80 percent in 2009. These amounts exclude the acquisition of Atlas Energy, Inc. in 2011. Refer to a discussion of the acquisition of Atlas Energy, Inc., in Note 2 to the Consolidated Financial Statements on page FS-30.

In 2012, the company estimates capital and exploratory expenditures will be $32.7 billion, including $3 billion of spending by affiliates. Approximately 87 percent of the total, or $28.5 billion, is budgeted for exploration and production activities, with $22.3 billion, or about 78 percent, of this amount for projects outside the United States.

Refer also to a discussion of the company s capital and exploratory expenditures on pages FS-11 through FS-12.

Upstream

The table on the following page summarizes the net production of liquids and natural gas for 2011 and 2010 by the company and its affiliates. Worldwide oil-equivalent production was 2.673 million barrels per day, down about three percent from 2010. The decrease was mainly associated with normal field declines, maintenance-related downtime and the impact of higher prices on entitlement volumes. The start-up and ramp-up of several major capital projects the Perdido project in the U.S. Gulf of Mexico, the expansion at the Athabasca Oil Sands Project in Canada, the Frade Field in Brazil, and the Platong II natural gas project in Thailand as well as acquisitions in the Marcellus Shale, partially offset the decrease in net production from 2010. Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of the factors explaining the 2009 2011 changes in production for crude oil and natural gas liquids, and natural gas.

The company estimates its average worldwide oil-equivalent production in 2012 will be approximately 2.680 million barrels per day based on the average Brent price of $111 per barrel in 2011. 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, 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. Refer to the Review of Ongoing Exploration and Production Activities in Key Areas, beginning on page 8, for a discussion of the company s major crude oil and natural gas development projects.

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

			Components of Oil-Equivalent			
	Oil-Equivalent (Thousands of Barrels per Day)		Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day)		Natural Gas (Millions of Cubic Feet per Day)	
	2011	2010	2011	2010	2011	2010
United States	**678**	708	**465**	489	**1,279**	1,314
Other Americas:						
Canada	**70**	54	**69**	53	**4**	4
Colombia	**39**	41			**234**	249
Brazil	**35**	24	**33**	23	**13**	7
Trinidad and Tobago	**31**	38		1	**183**	223
Argentina	**27**	32	**26**	31	**4**	5
Total Other Americas	**202**	189	**128**	108	**438**	488
Africa:						
Nigeria	**260**	253	**236**	239	**142**	86
Angola	**147**	161	**139**	152	**50**	52
Chad	**26**	28	**25**	27	**6**	6
Republic of the Congo	**23**	25	**21**	23	**10**	10
Democratic Republic of the Congo	**3**	2	**3**	2	**1**	1
Total Africa	**459**	469	**424**	443	**209**	155
Asia:						
Thailand	**209**	216	**65**	70	**867**	875
Indonesia	**208**	226	**166**	187	**253**	236
Partitioned Zone[2]	**91**	98	**88**	94	**20**	23
Bangladesh	**74**	69	**2**	2	**434**	404
Kazakhstan	**62**	64	**38**	39	**144**	149
Azerbaijan	**28**	30	**26**	28	**10**	11
Philippines	**25**	25	**4**	4	**126**	124
China	**22**	20	**20**	18	**10**	13
Myanmar	**14**	13			**86**	81
Total Asia	**733**	761	**409**	442	**1,950**	1,916
Australia	**101**	111	**26**	34	**448**	458
Europe:						
United Kingdom	**85**	97	**59**	64	**155**	194
Denmark	**44**	51	**29**	32	**91**	116

Netherlands	**7**	8	**2**	2	**31**	35
Norway	**3**	3	**3**	3	**1**	1
Total Europe	**139**	159	**93**	101	**278**	346
Total Consolidated Operations	**2,312**	2,397	**1,545**	1,617	**4,602**	4,677
Equity Affiliates[3]	**361**	366	**304**	306	**339**	363
Total Including Affiliates[4]	**2,673**	2,763	**1,849**	1,923	**4,941**	5,040

[1] Includes synthetic oil: Canada, net	**40**	24	**40**	24
Venezuelan affiliate, net	**32**	28	**32**	28

[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 582 million and 537 million cubic feet per day in 2011 and 2010, respectively. Total as sold natural gas volumes were 4,359 million and 4,503 million cubic feet per day for 2011 and 2010, respectively.

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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 2011, 2010 and 2009.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2011 for the company and its affiliates:

Productive Oil and Gas Wells at December 31, 2011

	Productive Oil Wells		Productive Gas Wells	
	Gross	**Net**	**Gross**	**Net**
United States	49,511	32,368	14,061	7,671
Other Americas	709	533	40	17
Africa	2,548	850	17	7
Asia	12,612	10,861	3,437	2,125
Australia	807	453	64	11
Europe	332	105	222	48
Total Consolidated Companies	66,519	45,170	17,841	9,879
Equity in Affiliates	1,231	434	7	2
Total Including Affiliates	67,750	45,604	17,848	9,881
Multiple completion wells included above:	887	573	378	280

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 2009 and each year-end from 2009 through 2011. 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, 2011, 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 2009 through 2011 are shown in the following table.

Net Proved Reserves at December 31

	2011	2010	2009
Liquids Millions of barrels			
Consolidated Companies	**4,295**	4,270	4,610
Affiliated Companies	**2,160**	2,233	2,363
Natural Gas Billions of cubic feet			
Consolidated Companies	**25,229**	20,755	22,153
Affiliated Companies	**3,454**	3,496	3,896
Total Oil-Equivalent Millions of barrels			
Consolidated Companies	**8,500**	7,729	8,303
Affiliated Companies	**2,736**	2,816	3,012

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Acreage

At December 31, 2011, 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, 2011
(Thousands of Acres)

	Undeveloped*		Developed		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States	6,290	5,171	7,752	5,051	14,042	10,222
Other Americas	26,803	15,338	1,392	395	28,195	15,733
Africa	8,068	3,921	3,324	1,370	11,392	5,291
Asia	41,125	21,613	5,426	2,760	46,551	24,373
Australia	12,801	6,064	920	240	13,721	6,304
Europe	5,093	3,608	645	137	5,738	3,745
Total Consolidated Companies	100,180	55,715	19,459	9,953	119,639	65,668
Equity in Affiliates	419	191	252	100	671	291
Total Including Affiliates	110,599	55,906	19,711	10,053	120,310	65,959

* The gross undeveloped acres that will expire in 2012, 2013 and 2014 if production is not established by certain required dates are 4,675, 5,993 and 2,903, 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 232 billion cubic feet of natural gas through 2014. 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 contracts 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 891 billion cubic feet of natural gas from 2012 through 2014 from operations in Australia, Colombia, Denmark and the Philippines to third parties. The 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 2011, 2010 and 2009.

The table on the next page 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, 2011. 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.

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Development Well Activity

	Wells Drilling at 12/31/11		Net Wells Completed 2011		2010		2009	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**105**	**62**	**909**	**9**	634	7	582	3
Other Americas	**8**	**4**	**37**		32		36	
Africa	**7**	**3**	**29**		33		40	
Asia	**85**	**37**	**549**	**15**	445	15	580	10
Australia	**1**							
Europe	**5**		**6**		4		7	
Total Consolidated Companies	**211**	**106**	**1,530**	**24**	1,148	22	1,245	13
Equity in Affiliates	**1**	**1**	**25**		8		6	
Total Including Affiliates	**212**	**107**	**1,555**	**24**	1,156	22	1,251	13

Exploration Activities

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, 2011. Exploratory wells are wells drilled to find and produce crude oil or natural gas in unproved areas and include delineation 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 12/31/11		Net Wells Completed 2011		2010		2009	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**2**	**2**	**5**	**1**	1	1	4	5
Other Americas	**2**	**1**	**1**			1	1	2
Africa	**3**	**1**	**1**		1		2	1
Asia	**1**	**1**	**10**	**1**	5	5	9	1
Australia	**1**	**1**	**4**	**1**	5	2	4	2
Europe	**2**	**1**		**1**				
Total Consolidated Companies	**11**	**7**	**21**	**4**	12	9	20	11
Equity in Affiliates			**1**					
Total Including Affiliates	**11**	**7**	**22**	**4**	12	9	20	11

Refer to Table I on page FS-62 for detail of the company s exploration expenditures and costs of unproved property acquisitions for 2011, 2010 and 2009.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron s 2011 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 gas business. The map at left indicates Chevron s primary areas of exploration and production.

a) United States

Upstream activities in the United States are concentrated in California, the Gulf of Mexico, the Appalachian Basin, Colorado, Michigan, New Mexico, Ohio, Oklahoma, Texas, Wyoming and Alaska. Average net oil-equivalent production in the United States during 2011 was 678,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2011, average net oil-equivalent production was 183,000 barrels per day, composed of 165,000 barrels of crude oil, 83 million cubic feet of natural gas and 4,000 barrels of natural gas liquids. Approximately 84 percent of the crude oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

Average net oil-equivalent production during 2011 for the company s combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region was 244,000 barrels per day. The daily oil-equivalent production was composed of 161,000 barrels of crude oil, 401 million cubic feet of natural gas and 16,000 barrels of natural gas liquids.

Chevron was engaged in various exploration and development activities in the deepwater Gulf of Mexico during 2011. The Jack and St. Malo fields are located within 25 miles of each other and are being jointly developed. Chevron has a 50 percent working interest in Jack and a 51 percent working interest in St. Malo. Both fields are company operated. All major installation contracts have been awarded and construction began for the floating production unit hull and topsides modules during 2011. Development drilling operations commenced in fourth quarter 2011. 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 project has an estimated production life of 30 years. The initial recognition of proved reserves for the project occurred in 2011.

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Work continued at the 60 percent-owned and operated Big Foot discovery. The development plan includes a 15-slot drilling and production tension leg platform with water injection facilities and a design capacity of 79,000 barrels of oil equivalent per day. Fabrication of topsides, hull and other components began in first-half 2011 and initial development drilling commenced in fourth quarter 2011. First production is anticipated in 2014. The field has an estimated production life of 20 years. Initial proved reserves were recognized in 2011.

Tahiti 2 is the second development phase for the 58 percent-owned and operated Tahiti Field and is designed to increase recovery and return well capacity to 125,000 barrels of oil per day. The project includes three water injection wells, two additional production wells and the water injection facilities required to deliver water to the injection wells. Two water injection wells have been completed and drilling commenced on the first production well in early 2012. The water injection facilities have been installed and water injection began in first quarter 2012. Start-up of the first production well of the second phase is expected by 2013. Initial proved reserves for the Tahiti 2 project were recognized in 2011, and the field has an estimated production life of 30 years.

The final investment decision was made for the Tubular Bells deepwater project in fourth quarter 2011. The company has a 42.9 percent nonoperated working interest in the Tubular Bells unitized area after receiving an additional 12.9 percent equity interest relinquished by a partner in 2011. Development drilling is scheduled to begin 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. At the end of 2011, proved reserves had not been recognized for this project.

The company has a 20.3 percent nonoperated working interest in the Caesar and Tonga unitized area. Development plans include a total of four wells and a subsea tieback to a nearby third-party production facility. Three of the four development wells have been drilled and completed as of year-end 2011. Drilling of the fourth well is expected to begin in mid-2012. Work on the subsea system, commissioning of the topsides and the initial well completion program continued into 2012. Installation of the production riser and first production are expected in mid-2012. Maximum total production is expected to be 46,000 barrels of oil-equivalent per day. Proved reserves have been recognized for the project.

The company has a 15.6 percent nonoperated working interest in the Mad Dog II Project. Front-end engineering and design (FEED) is expected to commence by second quarter 2012. It is anticipated that this future development would require new production facilities to support planned maximum total daily production of 120,000 to 140,000 barrels of oil equivalent. At the end of 2011, proved reserves had not been recognized for this project.

Development planning and unitization talks with owners of an adjacent field continued in 2011 for the Knotty Head project. Chevron has a 25 percent nonoperated working interest in this subsalt, Green Canyon Block 512 discovery. At the end of 2011, proved reserves had not been recognized for this project.

Deepwater exploration activities in 2011 included participation in four exploratory wells two wildcats, one appraisal and one delineation. Following successful permitting under new, more stringent, U.S. Department of Interior guidelines, two wells resumed drilling activities after operations were halted in 2010 as a result of the deepwater drilling moratorium in the Gulf of Mexico. Drilling operations at the 43.8 percent-owned and operated Moccasin prospect resumed in first quarter 2011 and resulted in a new discovery in the Lower Tertiary Wilcox Trend. Drilling operations resumed in second quarter 2011 at the 55 percent-owned and operated Buckskin prospect, resulting in a successful appraisal well. These two discoveries, located 12 miles apart, could facilitate future co-development upon the successful completion of additional appraisal drilling planned at each prospect in 2012. Drilling was terminated at the Coronado wildcat well due to drilling conditions in the shallow section of the wellbore. The company plans to drill a replacement well at an alternate location by mid-2012.

Besides the activities connected with the development and exploration projects in the Gulf of Mexico, the company also has contracted capacity at the third-party Sabine Pass liquefied natural gas (LNG) regasification terminal in Louisiana and in a third-party pipeline system connecting the Sabine Pass LNG terminal to the natural gas pipeline grid. The pipeline provides access to two major salt dome storage fields and 10 major interstate pipeline systems, including access to Chevron s Sabine Pipeline, which connects to the Henry Hub. The Henry Hub interconnects to nine interstate and four intrastate pipelines and is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange.

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Company activities outside California and the Gulf of Mexico include operated and nonoperated interests in properties across the mid-continental United States, the Appalachian Basin, Michigan, Ohio and Alaska. During 2011, the company s U.S. production outside California and the Gulf of Mexico averaged 251,000 net oil-equivalent barrels per day, composed of 91,000 barrels of crude oil, 795 million cubic feet of natural gas and 28,000 barrels of natural gas liquids.

In West Texas, the company continues to pursue development of tight carbonates, tight sands, 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 February 2011, Chevron acquired Atlas Energy, Inc. The acquisition provided a natural gas resource position in the Marcellus Shale and Utica Shale, primarily located in southwestern Pennsylvania and Ohio. The acquisition also provided a 49 percent interest in Laurel Mountain Midstream, LLC, an affiliate that owns more than 1,000 miles of natural gas gathering lines servicing the Marcellus. In addition, the acquisition provided assets in Michigan, which include Antrim Shale producing assets and approximately 350,000 total acres in the Antrim and Collingwood/Utica Shale formations. Additional asset acquisitions in 2011 expanded the company s holdings in the Marcellus and Utica to approximately 700,000 and 600,000 total acres, respectively. In the Marcellus, 61 natural gas wells were completed in 2011.

b) Other Americas

Other Americas is composed of Argentina, Brazil, Canada, Colombia, Greenland, Trinidad and Tobago, and Venezuela. Net oil-equivalent production from these countries averaged 267,000 barrels per day during 2011, including the company s share of synthetic oil production.

Canada: Company activities in Canada include nonoperated working interests of 26.9 percent in the Hibernia Field, 26.6 percent in the Hebron Field and 23.6 percent in the unitized Hibernia South Extension, all offshore eastern Canada. In Alberta, the company holds a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP). Average net oil-equivalent production during 2011 was 70,000 barrels per day, composed of 69,000 barrels of crude oil, synthetic oil and natural gas liquids and 4 million cubic feet of natural gas.

Development of the Hibernia Southern Extension is expected to stem the production decline from the Hibernia Field. The project includes drilling of producing wells from the existing Hibernia platform and subsea drilling of water injection wells. All project approvals were in place by early 2011 and two producing wells were successfully drilled from the platform to obtain early reservoir information. Further drilling is anticipated to commence in 2013 with full production start-up expected in 2014. The initial recognition of proved reserves occurred in 2011 for this project.

FEED activities continued in 2011 for the development of the heavy-oil Hebron Field and a final investment decision is expected in 2013. The project has an expected economic life of 30 years. At the end of 2011, proved reserves had not been recognized for this project.

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At AOSP, oil sands are mined from both the Muskeg River and Jackpine mines and bitumen is extracted from the oil sands and upgraded into synthetic oil. The AOSP Expansion 1 Project activities continued in 2011 with completion of the Scotford Upgrader expansion, which increased daily production design capacity to approximately 255,000 barrels per day.

During 2011, the company increased its shale exploration acreage in Alberta in the Duvernay formation. In third quarter 2011, a multiwell drilling program commenced on these 100 percent-owned and operated leases. A long-term well test is expected to begin in fourth quarter 2012, when the first well is expected to be tied into third-party processing facilities. The company also holds exploration licenses and leases in the Flemish Pass and Orphan basins offshore Atlantic Canada, the Mackenzie Delta region of the Northwest Territories and the Beaufort Sea region of Canada s Arctic, 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 with an approximate total capacity of 100 billion cubic feet. These facilities are located adjacent to the Duvernay, Horn River and Montney shale gas plays.

Greenland: In 2011, the Greenland government granted a one-year extension to the initial four-year term for License 2007/26, which includes Block 4 offshore West Greenland. Interpretation of seismic data continued into early 2012. Chevron has a 29.2 percent nonoperated working interest in this exploration license.

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 2011 averaged 27,000 barrels per day, composed of 26,000 barrels of crude oil and natural gas liquids and 4 million cubic feet of natural gas. During 2011, the company reached an agreement to extend the El Trapial concession for an additional 10 years until 2032. The company expects to drill two exploratory wells in 2012 in the Vaca Muerta formation, targeting shale gas and tight oil resources.

Brazil: Chevron holds working interests in three deepwater fields in the Campos Basin. Net oil-equivalent production in 2011 averaged 35,000 barrels per day, composed of 33,000 barrels of crude oil and 13 million cubic feet of natural gas.

During 2011, development drilling continued at the 51.7 percent-owned and operated Frade Field, located in the Campos Basin. Eleven development wells and four injection wells had been completed as of year-end 2011. Development drilling is planned to continue through 2013, with one additional development well, one sidetrack well and several injection wells. The concession that includes the Frade project expires in 2025.

In the partner-operated Campos Basin Block BC-20, two areas 37.5 percent-owned Papa-Terra and 30 percent-owned Maromba were retained for development following the end of the exploration phase of this block. During 2011, construction progressed on a floating production, storage and offloading (FPSO) vessel and tension leg well platform for the Papa-Terra project. Development drilling was initiated in fourth quarter 2011. The facility has a planned total daily capacity of 140,000 barrels of crude oil. First production is expected in 2013, and the initial recognition of proved reserves occurred during 2011. Evaluation of the field development concept for Maromba continued into early 2012. At the end of 2011, 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. During 2011, a gas export agreement with Venezuela was extended. An onshore, multiwell drilling program commenced in late 2011. Daily net production averaged 234 million cubic feet of natural gas in 2011.

Trinidad and Tobago: Company interests include 50 percent ownership in three partner-operated blocks in the East Coast Marine Area offshore Trinidad, which includes the Dolphin and Dolphin Deep producing natural gas fields and the Starfish discovery. Net production in 2011 averaged 183 million cubic feet of natural gas per day. Chevron also holds a

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50 percent operated interest in the Manatee Area of Block 6(d), which includes a 2005 discovery. During 2011, work progressed to mature a development concept called the Regional Cooperative Agreement.

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 2011 from these operations, including synthetic oil from Hamaca, averaged 65,000 barrels per day, composed of 60,000 barrels of crude oil, synthetic oil and natural gas liquids and 27 million cubic feet of natural gas.

Chevron holds a 34 percent interest in the Petroindependencia affiliate that is working on a heavy-oil project in three blocks within the Carabobo Area of eastern Venezuela s Orinoco Belt. During 2011, work continued toward commercialization of the Carabobo 3 Project. Conceptual engineering for the potential development of the concession is in progress.

The company operates and has a working interest of 60 percent in Block 2 in the Plataforma Deltana area offshore eastern Venezuela. During 2011, work progressed to mature a development concept called the Regional Cooperative Agreement.

c) Africa

In Africa, the company is engaged in exploration and production activities in Angola, Chad, Democratic Republic of the Congo, Liberia, Nigeria and Republic of the Congo. Net oil-equivalent production in Africa averaged 459,000 barrels per day during 2011.

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 area. Net production from these operations in 2011 averaged 147,000 barrels of oil-equivalent per day.

The company operates the 39.2 percent-owned Block 0, which averaged 108,000 barrels per day of net liquids production in 2011. The Block 0 concession extends through 2030.

Work on the second development stage of the Mafumeira Field in Block 0 continued in 2011. Mafumeira Sul, a project to develop the southern portion of the field, is expected to reach a final investment decision in second quarter 2012. Maximum total production from Mafumeira Sul is expected to be 110,000 barrels of crude oil and 10,000 barrels of LPG per day. At year-end 2011, proved reserves had not been recognized for the Mafumeira Sul project.

In the Greater Vanza/Longui Area of Block 0, development concept studies continued during 2011 and the project is expected to enter FEED in second-half 2012. FEED activities continued on the south extension

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of the N Dola Field development with a final investment decision expected in late 2012. At year-end 2011, no proved reserves were recognized for these projects.

In Block 0, the Area A gas management projects at the Takula and Malongo reservoirs were designed to eliminate routine flaring of natural gas. The final project entered service in 2011, which together have reduced flaring by approximately 70 million cubic feet per day, as of year-end 2011. In Area B, the first stage of the Nemba Enhanced Secondary Recovery and Flare Reduction Project was completed in second quarter 2011. The final stage is expected to eliminate routine flaring at the North and South Nemba platforms and is scheduled to begin gas injection in 2014.

Also in Block 0, a two-well appraisal and exploration program was completed in 2011. The appraisal well completed in July 2011 in the Lifua Field was successful and development opportunities are being evaluated. The second well, completed in October 2011 in the pre-salt play, was not successful. Two additional exploratory wells are planned for second-half 2012.

In the 31 percent-owned Block 14, net production in 2011 averaged 29,000 barrels of liquids per day. Development and production rights for the various producing fields in Block 14 expire between 2023 and 2028.

For the Lucapa Field in Block 14, development alternatives continued to be evaluated during 2011. The project is expected to enter FEED in second quarter 2012. Development alternatives were evaluated during the year at the Malange Field and the preferred alternative is expected to enter FEED in mid-2012. As of the end of 2011, development of the Negage Field remained suspended until cooperative arrangements between Angola and Democratic Republic of the Congo are finalized. At the end of 2011, 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 ownership interest in the Angola LNG affiliate that began construction in 2008 of an onshore natural gas liquefaction plant at 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 regasified LNG and up to 63,000 barrels of natural gas liquids. Construction continued during 2011, reaching mechanical completion at year-end. The first LNG shipment from the plant is expected in second quarter 2012. The estimated total cost of the LNG plant is $10 billion, with an estimated life in excess of 20 years. The company also holds a 38.1 percent interest in a pipeline project that is expected to transport up to 250 million cubic feet of natural gas per day from Block 0 and Block 14 to the Angola LNG plant. The pipeline project entered construction in May 2011 and is expected to be completed in late 2013. Proved reserves have been recognized for the producing operations associated with the Angola LNG project.

Angola Republic of the Congo Joint Development Area: Chevron operates and holds a 31.3 percent interest in the Lianzi Development Area located between Angola and Republic of the Congo. A final investment decision for the Lianzi development project is expected in mid-2012. The project is expected to commence production in late 2014. At the end of 2011, proved reserves had not been recognized for the project.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2011 averaged 3,000 barrels of oil-equivalent.

Republic of the Congo: Chevron has a 31.5 percent nonoperated working interest in the Nkossa, Nsoko and Moho-Bilondo permit areas and a 29.3 percent nonoperated working interest in the Kitina permit area, all of which are offshore. The development and production rights for Kitina, Nsoko, Nkossa and Moho-Bilondo expire in 2014, 2018, 2027 and 2030, respectively. Net production averaged 23,000 barrels of oil-equivalent per day in 2011.

The Moho Nord Project, located in the Moho-Bilondo Development Area, entered FEED in fourth quarter 2011. The project is expected to reach a final investment decision in 2013. At the end of 2011, 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 the crude oil to the coast of Cameroon. Average daily net production from the Chad fields in 2011 was 26,000 barrels of oil-equivalent. The Chad producing operations are conducted under a concession that expires in 2030.

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Nigeria: Chevron holds a 40 percent interest in 13 concessions predominantly in the onshore and near-offshore region 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 2011, the company s net oil-equivalent production in Nigeria averaged 260,000 barrels per day, composed of 236,000 barrels of liquids and 142 million cubic feet of natural gas.

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 2011, drilling continued on a 10-well, Phase 2 development program that is designed to offset field decline and maintain plateau production. The first well is expected to be completed and placed on production in second-half 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. During 2011, development drilling continued and the FPSO vessel was moored on location. Production start-up is expected in early 2012, with maximum total production of 180,000 barrels of crude oil per day expected within one year of start-up. The production-sharing contract (PSC) expires in 2023. Proved reserves have been recognized for this project.

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. Initiation of FEED is expected in late 2012. At the end of 2011, no proved reserves were recognized for this project.

In the Niger Delta, ramp-up activity continued at the Escravos Gas Plant (EGP). During 2011, 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 includes facilities to produce natural gas from the Sonam natural gas field in the Escravos area. The project is designed to utilize EGP and to deliver 215 million cubic feet of natural gas per day to the domestic market, and produce an average of 30,000 barrels of liquids per day. A final investment decision was reached in late 2011, and first production is expected in 2016. Proved reserves associated with the project were recognized in 2011.

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. At the end of 2011, work on the project was more than 80 percent complete and start-up is planned for 2013. The estimated cost of the plant is $8.4 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 activities continued through 2011, and start-up is scheduled for late 2012.

In deepwater exploration, the company has 20 percent and 27 percent nonoperated working interests in Oil Prospecting License (OPL) 214 and OPL 223, respectively. Drilling of two exploration wells commenced in fourth quarter 2011 in OPL 214, and one exploration well is planned in OPL 223 for second-half 2012. In addition, Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery in OML 140 where further exploration activities are planned.

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Shallow-water exploration activities in 2011 included reprocessing 3-D seismic data from OML 86 and OML 88. In November 2011, the company began drilling a well in OML 86. In January 2012, while drilling the well, there was a release of natural gas that led to a fire. Drilling of a relief well commenced in February 2012. A root cause investigation is under way.

Chevron is the largest shareholder, with a 37 percent interest, in the West African Gas Pipeline Company Limited affiliate, which constructed, 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: In 2010, Chevron acquired a 70 percent interest and operatorship in three deepwater blocks off the coast of Liberia. Exploration drilling prospects were identified during 2011 based on 3-D seismic data. Two exploration wells are planned to be drilled in 2012.

d) Asia

In Asia, the company is engaged in upstream activities in Azerbaijan, Bangladesh, Cambodia, China, Indonesia, Kazakhstan, Myanmar, the Partitioned Zone located between Saudi Arabia and Kuwait, the Philippines, Russia, Thailand, Turkey, and Vietnam. During 2011, net oil-equivalent production averaged 1,029,000 barrels per day.

Azerbaijan: Chevron holds an 11.3 percent nonoperated working interest in the Azerbaijan International Operating Company (AIOC), which produces crude oil in the Caspian Sea from the Azeri-Chirag-Gunashli (ACG) project. The company s daily net production from AIOC averaged 28,000 barrels of oil-equivalent in 2011. AIOC operations are conducted under a PSC that expires in 2024.

During 2011, construction progressed on the next development phase of the ACG project, which will further develop the deepwater Gunashli Field. Production is expected to begin in 2013. Proved reserves have been recognized for this project. The total estimated cost of the project is $6 billion, with maximum total daily production of 140,000 barrels of oil-equivalent.

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 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 2011 from these fields averaged 296,000 barrels per day, composed of 244,000 barrels of crude oil and natural gas liquids and 312 million cubic feet of natural gas. During 2011, 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.

Also during 2011, TCO continued to evaluate alternatives for another expansion project to increase total daily crude oil production between 250,000 and 300,000 barrels. The expansion project will rely on sour gas injection technology utilized in current operations. Approval of FEED is anticipated in 2012. As of year-end 2011, proved reserves had not been recognized for this expansion project.

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Chevron holds a 20 percent nonoperated working interest in the Karachaganak project, which is conducted under a PSC that expires in 2038. During 2011, Karachaganak net oil-equivalent production averaged 62,000 barrels per day, composed of 38,000 barrels of liquids and 144 million cubic feet of natural gas. In 2011, access to the CPC and Atyrau-Samara (Russia) pipelines enabled approximately 204,000 barrels per day (34,000 net barrels) of Karachaganak liquids to be sold at world-market prices. The remaining liquids were sold into local and Russian markets. During 2011, a fourth train entered production and increased total liquids-stabilization capacity by 56,000 barrels per day, allowing increased sales of condensate into world markets. Karachaganak project partners have reached an agreement allowing the government of Kazakhstan to become a 10 percent equity owner in the Karachaganak project. The transfer of equity to the government is anticipated to occur in June 2012 and will result in Chevron s working interest being reduced to 18 percent.

During 2011, Chevron and its partners continued to evaluate alternatives for a Phase III development of Karachaganak. The timing of the project remains uncertain until a project design is finalized. At the end of 2011, proved reserves had not been recognized for the project.

Kazakhstan/Russia: Chevron has a 15 percent interest in the CPC affiliate. During 2011, CPC transported an average of approximately 684,000 barrels of crude oil per day, including 608,000 barrels per day from Kazakhstan and 76,000 barrels per day from Russia. During 2011, the partners began construction on a project to increase pipeline capacity by 670,000 barrels per day. The total estimated cost of the project is $5.4 billion. The 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.

Turkey: In 2010, Chevron signed a Joint Operating Agreement for a 50 percent working interest in a 5.6 million acre exploration block located in the Black Sea. The initial exploration well completed in 2010 was unsuccessful. Future plans are under evaluation.

Bangladesh: Chevron holds a 98 percent interest in two operated PSCs covering Blocks 12, 13 and 14. Net oil-equivalent production from these operations in 2011 averaged 74,000 barrels per day, composed of 434 million cubic feet of natural gas and 2,000 barrels of liquids. In 2011, the Muchai compression project achieved mechanical completion and is expected to support additional production starting in second quarter 2012 from the Bibiyana, Jalalabad and Moulavi Bazar natural gas fields. Proved reserves have been recognized for this project. The Bibiyana Expansion Project entered FEED in July 2011. Project scope includes expansion of the gas plant, additional development drilling and an enhanced liquids recovery unit, with an estimated total maximum daily production of 57,000 barrels of oil equivalent. A final investment decision is expected in mid-2012. At the end of 2011, proved reserves had not been recognized for this project. Also in 2011, the company relinquished its interest in Block 7 subsequent to the completion of an unsuccessful exploratory well.

Cambodia: Chevron owns a 30 percent interest and operates the 1.2 million-acre Block A, located in the Gulf of Thailand. In 2011, the company progressed discussions on the production permit. Government approval and a final investment decision are expected by the end of 2012. At the end of 2011, 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 2011 was 86 million cubic feet per day.

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Thailand: Chevron has operated and nonoperated working interests in multiple offshore blocks. The company s net oil-equivalent production in 2011 averaged 209,000 barrels per day, composed of 65,000 barrels of crude oil and condensate and 867 million cubic feet of natural gas. All of the company s natural gas production is sold to PTT Public Company Limited, Thailand s national oil company, under long-term sales contracts.

Operated interests are 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 and North Arthit fields located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040.

Start-up of the 69.9 percent-owned and operated Platong II natural gas project occurred in October 2011, and total average daily production ramped up to 377 million cubic feet of natural gas and 11,000 barrels of condensate as of the end of 2011. Proved reserves have been recognized for this project.

During 2011, the company drilled nine exploration wells in the Pattani Basin. All of the wells were successful and development alternatives are being evaluated. The company also holds exploration interests in a number of blocks 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.

In the blocks off the southwest coast, the Block B Gas Development 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, a floating storage and offloading vessel, a central processing platform and a pipeline to shore. FEED continued during 2011. 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 is expected to be reached in 2012. At the end of 2011, proved reserves had not been recognized for the development project.

During the year, work continued on preparations for a 2012 exploration drilling program to further evaluate the potential of the three company-operated blocks in the Malay Basin. The company also completed the evaluation of Block 122 offshore eastern Vietnam and reached a decision to exit the block.

China: Chevron has operated and nonoperated working interests in several areas in China. The company s net oil-equivalent production in 2011 averaged 22,000 barrels per day, composed of 20,000 barrels of crude oil and condensate and 10 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 project includes two sour-gas processing plants with an aggregate design capacity of 740 million cubic feet per day connected by a natural gas gathering system to five fields. During 2011, the company continued construction on the first natural gas processing plant. In 2012, construction is expected to start at the second natural gas processing plant. Start-up of the initial phase of the project is expected in 2013, with planned maximum total natural gas production of 558 million cubic feet per day. Proved reserves have been recognized for this project. The PSC for Chuandongbei expires in 2037.

The company holds operating interests in three deepwater exploration blocks in the South China Sea. During the exploration phase, the company has a 100 percent

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working interest in Blocks 53/30 and 64/18, and a 59.2 percent working interest in Block 42/05 under three separate PSCs. The three deepwater blocks cover approximately 4.8 million acres. During 2011, a 3-D seismic acquisition program was completed for Blocks 64/18 and 53/30 and a three-well exploration program was initiated. The first well was unsuccessful. The second and third wells are expected to be completed by mid-2012.

The company signed a joint study agreement to explore for natural gas from shale resources in the Qiannan Basin in April 2011 and commenced seismic operations in July 2011.

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.

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 a 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 2011 from its interests in Indonesia averaged 208,000 barrels per day, composed of 166,000 barrels of liquids and 253 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. Government approval of the construction contract bid awards for North Duri Area 13 expansion project is expected in mid-2012 with start-up scheduled for 2013. The Rokan PSC expires in 2021.

During 2011, two deepwater development projects in the Kutei Basin progressed under a single plan of development. In the first of these projects, Chevron advanced FEED for the Gendalo-Gehem deepwater natural gas project. The project includes two separate hub developments, natural gas and condensate pipelines, and an onshore receiving facility. Maximum daily total 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 2011, proved reserves had not been recognized for this project.

In the second of these projects, FEED was completed in December 2011 for the Bangka deepwater natural gas project and the contracting approval process began with the government of Indonesia. The project scope includes a subsea tie back to a floating production unit. The company s working interest is 62 percent. At year-end 2011, proved reserves had not been recognized for this project.

Exploration activities continued in the Central Sumatra Basin where six successful appraisal wells were drilled in the Bekasap, Duri and Kulin fields in 2011, and evaluation of a well drilled in the Jorang Field continued in 2012. Also in 2011, seismic data acquisition was completed for West Papua I and is under way for West Papua III. Processing of the seismic data is planned for 2012.

In West Java, Chevron operates the wholly owned Salak geothermal field with a total power-generation capacity of 377 megawatts and holds a 95 percent interest in a power generation company that operates the Darajat geothermal contract area with a total capacity of 259 megawatts. Chevron also operates a 95 percent-owned 300-megawatt cogeneration facility in support of the company s operation in Duri, Sumatra. 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.

Partitioned Zone (PZ): Chevron holds a concession with the Kingdom of Saudi Arabia to operate the kingdom s 50 percent interest in the petroleum resources of the onshore area of the PZ between Saudi Arabia and Kuwait. Under the agreement, the company has rights to this 50 percent interest in the hydrocarbon resource until 2039.

During 2011, the company s average net oil-equivalent production was 91,000 barrels per day, composed of 88,000 barrels of crude oil and 20 million cubic feet of natural gas. During 2011, 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 progressed during 2011 and is expected to enter FEED in second-half 2012. At the end of 2011, proved reserves had not been recognized for these projects.

Also in 2011, the Central Gas Utilization Project entered FEED. The project is intended to increase natural gas utilization and eliminate routine flaring. A final investment decision is expected in 2013. At year-end 2011, proved reserves had not been recognized for this project.

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 2011 averaged 25,000 barrels per day, composed of 126 million cubic feet of natural gas and 4,000 barrels of condensate. During 2011, studies were progressed to maintain capacity.

Chevron also develops and produces geothermal resources under an agreement with the Philippine government. During 2011, efforts continued to seek a new 25-year contract with the government for the continued operation of the steam fields, which supply geothermal resources to third-party, 637-megawatt power generation facilities in southern Luzon. 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.

e) Australia

In Australia, the company s exploration and production efforts are concentrated off the northwest coast. During 2011, the average net oil-equivalent production from Australia was 101,000 barrels per day.

Chevron has a 16.7 percent nonoperated working interest in the North West Shelf (NWS) Venture offshore Western Australia. Daily net production from the project during 2011 averaged 18,000 barrels of crude oil and condensate, 445 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 NWS Venture continues to progress two major capital projects North Rankin 2 and NWS Oil Redevelopment. The North Rankin 2 project is designed to recover remaining low-pressure natural gas from the North Rankin and Perseus natural gas fields to meet gas supply needs and maintain production capacity of NWS. The North Rankin B platform was completed and installed during 2011. Maximum total daily production is expected to be about 2 billion cubic feet of natural gas and 39,000 barrels of condensate. Total estimated projects costs are $5.4 billion and start-up is expected in 2013. Proved reserves have been recognized for the project.

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The NWS Oil Redevelopment Project recommenced production from the Cossack, Hermes, Lambert and Wanaea fields in September 2011. The project included replacement of an FPSO vessel and a portion of existing subsea infrastructure. The project is expected to extend production from these fields beyond 2020.

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 field. The project s scope includes a three-train, 15 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 about 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate. Total estimated project costs for the first phase of development are $37 billion.

Work on the Gorgon Project progressed on schedule. As of year-end 2011, more than one-third of the construction activities across numerous fronts on Barrow Island and in fabrication yards in various countries had been completed. The development drilling program also commenced in July 2011.

Through year-end 2011, Chevron has signed binding LNG Sales and Purchase Agreements (SPAs) with six Asian customers for delivery of about 4.7 million metric tons of LNG per year, which brings delivery commitments to about 70 percent of Chevron s share of LNG from this project. Discussions continue with potential customers to increase long-term sales to 85 to 90 percent of Chevron s net LNG off-take. Binding SPAs were also signed in 2011 for delivery of about 55 million cubic feet per day of natural gas to two Western Australian state-owned utilities starting in 2015. Proved reserves have been recognized for the Greater Gorgon Area fields included in the project, and first production of natural gas from the fields is expected in late 2014. The project s estimated economic life exceeds 40 years from the time of start-up.

A project for development of a fourth train at the Gorgon LNG facility is expected to enter FEED in late 2012. At the end of 2011, proved reserves had not been recognized for the fields associated with this expansion.

Chevron and its joint-venture partners are proceeding with development of the Wheatstone Project. In September 2011, the company announced the final investment decision. Construction started in late 2011. Chevron holds a 72.1 percent interest in the foundation natural gas processing facilities, which include a two-train, 8.9 million-metric-ton-per-year LNG facility and a separate domestic gas plant located at Ashburton North, along the northwest coast of Australia. The company plans to supply natural gas to the foundation project from the company-operated and 90.2 percent-owned Wheatstone and Iago fields. Maximum total daily production is expected to be about 1.4 billion cubic feet of natural gas and 25,000 barrels of condensate. The LNG facilities will also be a destination for third-party natural gas. Total estimated project costs for the first phase of development are $29 billion.

Through the end of 2011, Chevron has signed binding SPAs with two Asian customers for the delivery of about 60 percent of Chevron s net LNG off-take from the Wheatstone Project. Discussions continue with potential customers to increase long-term sales to 85 to 90 percent of Chevron s net LNG off-take and to sell down equity. Start-up of the first LNG train is expected in 2016. During 2011, the company recognized proved reserves for this project.

In the Browse Basin, the Browse LNG development participants entered FEED in 2011, undertaking environmental, geophysical, geotechnical and engineering and design studies for the Brecknock, Calliance and Torosa fields. At the end of 2011, proved reserves had not been recognized for any of the Browse Basin fields.

During 2011, the company announced a natural gas discovery at the 50 percent-owned and operated Orthrus Deep prospect in Block WA-24-R. The company also announced natural gas discoveries at the 50 percent-owned and operated Vos prospect in WA-439-P and the 67 percent-owned and operated Acme West prospect in Block WA-205-P in 2011, and at the 50 percent-owned and operated Satyr-3 prospect in WA-374-P in January 2012. These discoveries are expected to support potential expansion opportunities at company-operated LNG facilities.

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f) Europe

In Europe, the company is engaged in exploration and production activities in Bulgaria, Denmark, the Netherlands, Norway, Poland, Romania and the United Kingdom. Net oil-equivalent production in Europe averaged 139,000 barrels per day during 2011.

Denmark: Chevron has a 15 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 2011 from DUC averaged 44,000 barrels per day, composed of 29,000 barrels of crude oil and 91 million cubic feet of natural gas.

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 2011, the company s net oil-equivalent production from the producing blocks was 7,000 barrels per day, composed of 2,000 barrels of crude oil and 31 million cubic feet of natural gas. In fourth quarter 2011, the second stage of the A/B Gas Project achieved first 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 2011. Chevron is the operator and has a 40 percent working interest in exploration license PL 527. In 2011, Chevron was awarded a 40 percent-owned and operated interest in exploration license PL 598. Both licenses are in the deepwater portion of the Norwegian Sea.

United Kingdom: The company s average net oil-equivalent production in 2011 from 10 offshore fields was 85,000 barrels per day, composed of 59,000 barrels of crude oil and natural gas liquids and 155 million cubic feet of natural gas. Most of the production was from 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.

The final investment decision was reached in fourth quarter 2011 for the Clair Ridge Project, located west of the Shetland Islands, in which the company has a 19.4 percent nonoperated working interest. Total design capacity is planned to be 120,000 barrels of crude oil per day, and total estimated projects costs are $7 billion. Production is scheduled to begin in 2016. Initial proved reserves were recognized for this phase of the project in 2011.

At the 70 percent-owned and operated Alder discovery, FEED activities progressed during 2011 and a final investment decision is planned for late 2012. In the 40 percent-owned and operated Rosebank area northwest of the Shetland Islands, seismic, geophysical, geotechnical and environmental surveys were completed during 2011, and FEED is expected to begin in the second-half 2012. At the end of 2011, proved reserves have not been recognized for these projects.

Also west of the Shetland Islands, a three-well exploration and appraisal drilling program continued through 2011 and was completed in early 2012. This program comprised exploration wells on the Lagavulin and Aberlour prospects and appraisal drilling and well testing of the Cambo discovery. The Lagavulin well was unsuccessful and the results from the other wells are under evaluation. Licenses P1196 (Lagavulin) and P1165 (Talisker) were relinquished in November 2011 at the termination of the license period.

In addition, the company entered into a master regasification agreement for access to available capacity at the South Hook LNG terminal in southwest Wales in 2011.

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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 exploration and production. Chevron is continuing to work closely with the government of Bulgaria to provide the necessary assurances to the government and the public that hydrocarbons from shale can be developed safely and responsibly.

Poland: Chevron holds four shale concessions in southeast Poland (Grabowiec, Zwierzyniec, Krasnik and Frampol). All four exploration licenses are 100 percent-owned and operated and comprise a total of 1.1 million acres. In 2011, Chevron focused on processing data from a 2-D seismic survey. The data is being used to plan a multiwell drilling program that commenced in fourth quarter 2011.

Romania: The company holds a 100 percent interest in the EV-2 Barlad shale concession. This license, located in northeast Romania, covers 1.6 million acres. In 2011, the company acquired 2-D seismic data across the EV-2 Barlad concession. A multiwell drilling program is expected to begin in late 2012. Also during 2011, the company continued negotiations on license agreements for three shale exploration blocks in southeast Romania, Blocks 17, 18 and 19, which comprise approximately 670,000 acres.

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 2011, U.S. and international sales of natural gas were 5.8 billion and 4.4 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, the Philippines and Thailand.

U.S. and international sales of natural gas liquids were 161 thousand and 87 thousand barrels per day, respectively, in 2011. Substantially all of the international sales of natural gas liquids are from company 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 2011, the company had a refining network capable of processing about 2 million barrels of crude oil per day. Operable capacity at December 31, 2011, and daily refinery inputs for 2009 through 2011 for the company and affiliate refineries were as follows:

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

Locations		December 31, 2011 Number	December 31, 2011 Operable Capacity	Refinery Inputs 2011	Refinery Inputs 2010	Refinery Inputs 2009
Pascagoula	Mississippi	**1**	**330**	**327**	325	345
El Segundo	California	**1**	**269**	**244**	250	247
Richmond	California	**1**	**257**	**192**	228	218
Kapolei	Hawaii	**1**	**54**	**47**	46	49
Salt Lake City	Utah	**1**	**45**	**44**	41	40
Perth Amboy[1]	New Jersey	**1**	**80**			
Total Consolidated Companies	**United States**	**6**	**1,035**	**854**	890	899
Pembroke[2]	United Kingdom			**122**	211	205
Cape Town[3]	South Africa	**1**	**110**	**77**	70	72
Burnaby, B.C.	Canada	**1**	**55**	**43**	40	49
Total Consolidated Companies	**International**	**2**	**165**	**242**	321	326
Affiliates[4]	Various Locations	**7**	**767**	**691**	683	653
Total Including Affiliates	**International**	**9**	**932**	**933**	1,004	979
Total Including Affiliates	**Worldwide**	**15**	**1,967**	**1,787**	1,894	1,878

1 Perth Amboy has been idled since early 2008 and is operated as a terminal.
2 Pembroke was sold in August 2011.
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 2012.
4 Includes 1,000, 2,000 and 4,000 barrels per day of refinery inputs in 2011, 2010 and 2009, respectively, for interests in refineries that were sold during those periods.

Average crude oil distillation capacity utilization during 2011 was 89 percent, compared with 92 percent in 2010. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 89 percent in 2011, compared with

95 percent in 2010. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 85 percent and 84 percent of Chevron s U.S. refinery inputs in 2011 and 2010, 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. Project completion is expected by year-end 2013. In February 2012, the company signed an agreement to sell its idled 80,000-barrel-per-day refinery, which is operating as a terminal, at Perth Amboy. The sale is expected to close in second quarter 2012.

At the refinery in El Segundo, construction progressed on 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. Project completion is expected in third quarter 2012. At the Richmond Refinery, the company filed an application for a conditional use permit for a revised project and the City of Richmond published its Notice of Preparation of the revised Environmental Impact Report in second quarter 2011. The project is designed to improve the refinery s ability to process higher sulfur crudes, without changing the refinery s capacity to process crude blends in the intermediate-light gravity range. Improved ability to process higher sulfur crudes is expected to provide increased flexibility to process lower API-gravity crudes within the refinery s existing capacity range. Refer also to a discussion of contingencies related to this project in Note 24 to the Consolidated Financial Statements on page FS-57.

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Outside the United States, GS Caltex, the company s 50 percent-owned affiliate, progressed the construction of a 53,000-barrel-per-day gas oil fluid catalytic cracking unit at the Yeosu Refinery in South Korea. The unit is scheduled for start-up in 2013. The unit is designed to increase high-value product yield and lower feedstock costs. Construction continued on modifications to the 64 percent-owned Star Petroleum Refinery in Thailand to meet regional specifications for cleaner fuels. Project completion is scheduled for 2012. During August 2011, the company completed the sale of the Pembroke Refinery in the United Kingdom. Also in 2011, Caltex Australia Ltd., the company s 50 percent-owned affiliate, initiated a review of its refining operations in Australia, which is ongoing.

Marketing Operations

The company markets petroleum products under the principal brands of Chevron, Texaco and Caltex throughout many parts of the world. The table below identifies the company s and affiliates refined products sales volumes, excluding intercompany sales, for the three years ended December 31, 2011.

Refined Products Sales Volumes
(Thousands of Barrels per Day)

	2011	**2010**	**2009**
United States			
Gasoline	**649**	700	720
Jet Fuel	**209**	223	254
Gas Oil and Kerosene	**213**	232	226
Residual Fuel Oil	**87**	99	110
Other Petroleum Products[1]	**99**	95	93
Total United States	**1,257**	1,349	1,403
International[2]			
Gasoline	**447**	521	555
Jet Fuel	**269**	271	264
Gas Oil and Kerosene	**543**	583	647
Residual Fuel Oil	**233**	197	209
Other Petroleum Products[1]	**200**	192	176
Total International	**1,692**	1,764	1,851
Total Worldwide[2]	**2,949**	3,113	3,254

[1] Principally naphtha, lubricants, asphalt and coke.			
[2] Includes share of equity affiliates sales:	**556**	562	516

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2011, the company supplied directly or through retailers and marketers approximately 8,170 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 490 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 9,660 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. The company markets in Latin America and the Caribbean 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 affiliate, GS Caltex, and in Australia through its 50 percent-owned affiliate, Caltex Australia Limited.

The company continued its ongoing effort to concentrate downstream resources and capital on strategic assets. In 2011, the company completed the sale of its fuels marketing and aviation businesses in 16 countries in the Caribbean and Latin America and certain marketing businesses in five countries in Africa. In August 2011, the company also completed the sale of its marketing businesses in Ireland and the United Kingdom. In 2012, the company expects to complete the sale of its fuels marketing, finished lubricants and aviation fuels businesses in Spain as well as certain fuels marketing and aviation businesses in the central Caribbean, following receipt of required local regulatory and government approvals. In addition, the company converted more than 240 company-operated service stations into retailer-owned sites in various countries outside the United States.

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Chevron markets commercial aviation fuel at approximately 170 airports worldwide. The company also markets an extensive line of lubricant and coolant products under the brand names Havoline, Delo, Ursa, Meropa and Taro.

Chemicals Operations

Chevron owns a 50 percent interest in its Chevron Phillips Chemical Company LLC (CPChem) affiliate. At the end of 2011, CPChem owned or had joint-venture interests in 38 manufacturing facilities and four research and technical centers around the world.

CPChem s 35 percent-owned Saudi Polymers Company expects to commence commercial operations on a new petrochemical project in Al Jubail, Saudi Arabia, in 2012. The joint-venture project includes olefins, polyethylene, polypropylene, 1-hexene and polystyrene units.

In the United States, CPChem continued with plans to construct a 1-hexene plant at the company s Cedar Bayou complex in Baytown, Texas, capable of producing in excess of 200,000 tons per year. Start-up is expected in 2014. The plant is expected to be the largest 1-hexene unit in the world and will utilize CPChem s proprietary 1-hexene technology. CPChem is also conducting a feasibility study to evaluate a potential U.S. Gulf Coast ethylene cracker and derivatives complex to capitalize on advantaged feedstock sourced from emerging shale gas development in North America.

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 February 2012, the company reached a final investment decision to significantly increase the capacity of the existing additives plant in Singapore.

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, 2011

	Net Mileage[1,2]
United States:	
Crude Oil	2,115
Natural Gas	2,282
Petroleum Products	6,125
Total United States	10,522
International:	
Crude Oil	700
Natural Gas	699

Petroleum Products	311
Total International	1,710
Worldwide	12,232

[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.

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Work was completed in first quarter 2012 to return the Cal-Ky Pipeline to crude oil service as a supply line for the Pascagoula Refinery. This crude oil pipeline is also expected to provide additional outlets for the company s equity production. The company is leading the construction of a 136 mile, 24-inch pipeline from the Jack/St. Malo facility to Green Canyon 19 in the U.S. Gulf of Mexico, where there is an interconnect to pipelines delivering crude oil into Texas and Louisiana.

Refer to pages 14, 16 and 17 in the Upstream section for information on the Chad/Cameroon pipeline, the West Africa 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 2011. During 2011, the company had 48 deep-sea vessels chartered on a voyage basis, or for a period of less than one year. The table below summarizes the capacity of the company s controlled fleet.

Controlled Tankers at December 31, 2011[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	17	25.0
Time-Chartered[2]			13	10.5
Total	4	1.4	31	36.6

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 between the Gulf Coast and the East Coast and from California refineries to terminals on the West Coast and in Alaska and Hawaii. The company retired one U.S.-flagged product tanker in 2011.

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 to and from various locations worldwide.

In addition to the vessels described above, the company has 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 continues its efforts to divest its remaining coal mining operations. The company completed the sale of the North River Mine and other coal-related assets in Alabama in second quarter 2011, and the sale of its Kemmerer, Wyoming, surface coal mine in first quarter 2012. The company is pursuing 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 2011 at the company-operated surface coal mine in McKinley, New Mexico, which ceased coal production at the end of 2009.

At year-end 2011, Chevron had 153 million tons of proven and probable coal reserves in the United States, including reserves of low-sulfur coal. Coal sales from wholly owned mines in 2011 were 6 million tons, down about 2 million tons from 2010.

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In addition to the coal operations, Chevron owns and operates the Questa molybdenum mine in New Mexico. At year-end 2011, Chevron had 53 million pounds of proven molybdenum reserves at Questa. Production and underground development at Questa continued at reduced levels in 2011 in response to weak prices for molybdenum.

Power Generation

Chevron s Global Power Company manages interests in 13 power assets with a total operating capacity of more than 3,100 megawatts, primarily through joint ventures in the United States and Asia. Twelve 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 13th 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.

The company has major geothermal operations in Indonesia and the Philippines and is investigating 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 pages 19 and 20 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. Since 2000, CES has developed hundreds of projects that have helped customers reduce their energy costs and environmental impact. Projects announced in 2011 include the City of Dinuba solar project in California; the Houston Independent School District renewable and energy efficiency project in Texas; the Eglin Air Force Base energy management systems upgrade project in Florida; and the Oceanic Time Warner solar project in Hawaii.

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 Technology Ventures (CTV) manages investments and projects in emerging energy technologies and their integration into Chevron s core businesses. As of the end of 2011, CTV continued to explore technologies such as next-generation biofuels and advanced solar. In 2011, the company completed construction and commissioned the world s largest solar-to-steam generation project for use in enhanced-oil-recovery operations in Coalinga, California. The project will test the viability of using solar power to produce steam to improve oil recovery.

Chevron s research and development expenses were $627 million, $526 million and $603 million for the years 2011, 2010 and 2009, 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.

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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. In late 2011, upon detection of ocean floor oil seeps in the deepwater Frade Field in Brazil, Chevron rapidly deployed capabilities and processes in coordination with OSRL. In early 2012, the company rapidly deployed response capabilities to address a natural gas well control incident in Nigeria.

Virtually all aspects of the company s businesses are subject to various U.S. federal, state and local environmental, health and safety laws and regulations and to similar laws and regulations in other countries. These regulatory requirements continue to change and increase in both number and complexity and to govern not only the manner in which the company conducts its operations, but also the products it sells. Most of the costs of complying with the many laws and regulations pertaining to the company s operations are, or are expected to become, embedded in the normal costs of conducting business.

In 2011, the company s U.S. capitalized environmental expenditures were $345 million, representing about 3 percent of the company s total consolidated U.S. capital and exploratory expenditures. These environmental expenditures include capital outlays to retrofit existing facilities as well as those associated with new facilities. The expenditures relate mostly to air- and water-quality projects and activities at the company s refineries, oil and gas producing facilities, and marketing facilities. For 2012, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $410 million. The future annual capital costs are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Regulations intended to protect the environment, including those intended to address concerns about greenhouse gas emissions and global climate change, continue to evolve. Legislation, regulations and market-based programs that could affect the company s operations exist at the international or multinational (such as the Kyoto Protocol and the European Union s Emissions Trading System), national (such as the U.S. Environmental Protection Agency s rules for stricter emission standards and increased renewable fuel content for transportation fuels), and regional (such as California s Global Warming Solutions Act) levels.

Refer to Management s Discussion and Analysis of Financial Condition and Results of Operations on pages FS-14 through FS-16 for additional information on environmental matters and their impact on Chevron and on the company s 2011 environmental expenditures, remediation provisions and year-end environmental reserves. Refer also to Item 1A. Risk Factors on pages 29 through 31 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 with 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 crude oil prices.

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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 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 on 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.

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 cover fully 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, 2011, 22 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-two percent of the company s net proved reserves, including affiliates, were located in OPEC countries at December 31, 2011.

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 operations 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.

Item 1B. Unresolved Staff Comments

None.

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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-76. Note 13, Properties, Plant and Equipment, to the company s financial statements is on page FS-41.

Item 3. Legal Proceedings

Ecuador
Information related to Ecuador matters is included in Note 14 to the Consolidated Financial Statements under the heading Ecuador, beginning on page FS-41.

Certain Governmental Proceedings
In November 2008, the California Air Resources Board (CARB) proposed a civil penalty against Chevron s Sacramento, California, terminal for alleged violations between August and December 2007 of CARB s regulations governing the minimum concentration of additives in gasoline. Due to a computer programming error, the Sacramento terminal s automatic dispensers allegedly failed to inject additive detergent into a gasoline line. It appears that the resolution of these notices of violation may result in the payment of a civil penalty exceeding $100,000.

In November 2008, CARB proposed a civil penalty against Chevron s Richmond, California, refinery for a notice of violation relating to gasoline that was not properly certified as to composition. The composition certificates for the gasoline were corrected without requiring any change to the composition of the gasoline. In July 2009, CARB issued the refinery a notice of violation relating to an error in gasoline blending that caused the product composition certifications to be in error. The composition certifications were corrected without requiring any change to the gasoline. Discussions with CARB officials relating to all of these matters continue. It appears that the resolution of these notices of violation may result in the payment of a civil penalty exceeding $100,000.

In July 2009, CARB issued a notice of violation against Chevron Products Company for alleged violations of CARB s regulations governing the certification of gasoline that occurred during storage at a third-party facility and which had been self-reported by Chevron on discovery. Chevron believes that this matter will not result in the payment of a civil penalty exceeding $100,000.

In 2011, 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. It appears that the resolution of these notices of violation may result in the payment of a civil penalty exceeding $100,000.

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 DOH. Chevron has disputed many of the allegations.

Chevron has entered into negotiations with the EPA with respect to alleged air quality violations at Chevron s Perth Amboy, New Jersey refinery identified in a September 16, 2008 Compliance Order issued by the EPA. The alleged violations relate to certain management and reporting requirements set forth in the EPA s Leak Detection and Repair regulations (these regulations pertain to the control and monitoring of fugitive emissions from refinery process equipment). Based on discussions with the EPA, it appears that the resolution of this matter may result in the payment of a civil penalty exceeding $100,000.

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 pollution 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 a 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. Based on a July 8, 2011, settlement communication with the SCAQMD, it appears that the resolution of this NOV may result in the payment of a civil penalty exceeding $100,000.

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Chevron reached a final resolution of an administrative penalty proceeding brought by the Utah Department of Environmental Quality by agreeing to pay the State of Utah a civil penalty of $500,000 as the result of two crude oil releases. The first release occurred in June 2010 and the second occurred in December 2010. In addition, Chevron agreed to pay the State of Utah and the Salt Lake City Corporation $4 million in damages and restoration projects. The public review period passed and the penalty has been paid.

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, 2011	**4,379,887**	**99.86**	**4,378,905**	
Nov. 1 Nov. 30, 2011	**4,173,725**	**102.18**	**4,170,000**	
Dec. 1 Dec. 31, 2011	**3,738,606**	**103.63**	**3,730,500**	
Total Oct. 1 Dec. 31, 2011	**12,292,218**	**101.80**	**12,279,405**	

(1) Pertains to common shares repurchased during the three-month period ended December 31, 2011, from company employees for required personal income tax withholdings on the exercise of the stock options issued to management under long-term incentive plans and former Texaco Inc. and Unocal stock option plans. Also includes shares delivered or attested to in satisfaction of the exercise price by holders of certain former Texaco Inc. employee stock options exercised during the three-month period ended December 31, 2011.

(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, 2011, 51,064,679 shares had been acquired under this program for $5.0 billion.

Item 6. Selected Financial Data

The selected financial data for years 2007 through 2011 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-13 and in Note 10 to the Consolidated Financial Statements, Financial and Derivative Instruments, beginning on page FS-36.

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, 2011.

(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, 2011.

The effectiveness of the company s internal control over financial reporting as of December 31, 2011, 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, 2011, 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 23, 2012

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	55	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	61	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	53	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	51	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	54	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	55	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	49	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 2012 Annual Meeting and 2012 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 2012 Annual Meeting of Stockholders (the 2012 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 2012 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 2012 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 2012 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 2012 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 2012 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 2012 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 2012 Proxy Statement shall not be deemed to be solicited 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 2012 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 2012 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 2012 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 2012 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 2012 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 38 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.

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Schedule

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS
Millions of Dollars

	Year Ended December 31		
	2011	**2010**	**2009**
Employee Termination Benefits:			
Balance at January 1	**$ 145**	$ 13	$ 44
Additions (deductions) charged (credited) to expense		235	(12)
Payments	**(82)**	(103)	(19)
Balance at December 31	**$ 63**	$ 145	$ 13
Allowance for Doubtful Accounts:			
Balance at January 1	**$ 239**	$ 293	$ 275
Additions (reductions) to expense	**4**	(13)	92
Bad debt write-offs	**(76)**	(41)	(74)
Balance at December 31	**$ 167**	$ 239	$ 293
Deferred Income Tax Valuation Allowance:*			
Balance at January 1	**$ 9,185**	$ 7,921	$ 7,535
Additions to deferred income tax expense	**2,216**	1,454	2,204
Reduction of deferred income tax expense	**(305)**	(190)	(1,818)
Balance at December 31	**$ 11,096**	$ 9,185	$ 7,921

* See also Note 15 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 23rd day of February, 2012.

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 23rd day of February, 2012.

Principal Executive Officers (and Directors)

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

/s/George L. Kirkland
George L. Kirkland, Vice Chairman of the Board

Principal Financial Officer

/s/Patricia E. Yarrington
Patricia E. Yarrington, Vice President and Chief Financial Officer

Principal Accounting Officer

/s/Matthew J. Foehr
Matthew J. Foehr, Vice President and Comptroller

Directors

Linnet F. Deily*
Linnet F. Deily

Robert E. Denham*
Robert E. Denham

Robert J. Eaton*
Robert J. Eaton

Chuck Hagel*
Chuck Hagel

Enrique Hernandez, Jr.*
Enrique Hernandez, Jr.

Donald B. Rice*
Donald B. Rice

Kevin W. Sharer*
Kevin W. Sharer

Charles R. Shoemate*
Charles R. Shoemate

John G. Stumpf*
John G. Stumpf

*By: /s/Lydia I. Beebe	Ronald D. Sugar*
Lydia I. Beebe,	Ronald D. Sugar
Attorney-in-Fact	
	Carl Ware*
	Carl Ware

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

Key Financial Results

Millions of dollars, except per-share amounts	**2011**	2010	2009
Net Income Attributable to Chevron Corporation	**$ 26,895**	$ 19,024	$ 10,483
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
Basic	**$ 13.54**	$ 9.53	$ 5.26
Diluted	**$ 13.44**	$ 9.48	$ 5.24
Dividends	**$ 3.09**	$ 2.84	$ 2.66
Sales and Other Operating Revenues	**$ 244,371**	$ 198,198	$ 167,402
Return on:			
Capital Employed	**21.6%**	17.4%	10.6%
Stockholders Equity	**23.8%**	19.3%	11.7%

Earnings by Major Operating Area

Millions of dollars	**2011**	2010	2009
Upstream[1]			
United States	**$ 6,512**	$ 4,122	$ 2,262
International	**18,274**	13,555	8,670
Total Upstream	**24,786**	17,677	10,932
Downstream[1]			
United States	**1,506**	1,339	(121)
International	**2,085**	1,139	594
Total Downstream	**3,591**	2,478	473
All Other	**(1,482)**	(1,131)	(922)
Net Income Attributable to Chevron Corporation[2,3]	**$ 26,895**	$ 19,024	$ 10,483

[1] 2009 information has been revised to conform with the 2011 and 2010 segment presentation.

[2] Includes foreign currency effects:	**$ 121**	$ (423)	$ (744)

[3] 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, 2011.

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 single biggest factor that affects the results of operations for the company is movement in 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 also 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 2011. 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 monitors developments closely 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 West Texas Intermediate (WTI) crude oil, Brent crude oil and U.S. Henry Hub natural gas. The WTI price averaged $95 per barrel for the full-year 2011, compared to $79 in 2010. As of mid-February 2012, the WTI price was about $99 per barrel. The Brent price averaged $111 per barrel for the full-year 2011, compared to $80 in 2010. As of mid-February 2012, the Brent price was about $118 per barrel. The majority of the company s equity crude production is priced based on the Brent benchmark. WTI traded at a discount to Brent throughout 2011 due to excess crude supply in the U.S. Midcontinent market. The discount narrowed in fourth quarter 2011 as crude inventories declined.

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). The differential widened during 2011 primarily due to rising diesel prices and lower availability of light, sweet crude oil due to supply disruptions in Libya.

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 about $4.00 per thousand cubic feet (MCF) during 2011, compared with about $4.50 during 2010. As of mid-February 2012, the Henry Hub spot price was about $2.50 per MCF. Fluctuations in the price for natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America.

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 $5.40 per MCF during 2011, compared with about $4.60 per MCF during 2010. (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 2011 averaged 2.673 million barrels per day. About one-fifth of the company s net oil-equivalent production in 2011 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 2011 or 2010. At their December 2011 meeting, members of OPEC supported maintaining the current production level of 30 million barrels per day and made no change to the production quotas in effect since December 2008.

The company estimates that oil-equivalent production in 2012 will average approximately 2.680 million barrels per day based on the average Brent price of $111 per barrel for the full-year 2011. 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, 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 2009 and each year-end from 2009 through 2011, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2011.

In early November 2011, while drilling a development well in the deepwater Frade Field in 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 resulting surface sheen has since dissipated and there have been no coastal or wildlife impacts. Upon detection, the company immediately took steps to stop the release. Chevron s emergency plan, approved by the Brazilian environment and natural resources regulatory agency IBAMA, was implemented according to the law and industry standards. The source of the seep was contained within four days. As of December 31, 2011 the financial impact of the incident was not material to the company s annual net income. However, the company s ultimate exposure related to fines and penalties is not currently determinable, and could be significant to net income in any one period.

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. In

2011, the company s margins improved over 2010, supported by higher global product demand and tighter global refined product supplies. The company made further progress during 2011 implementing the previously-announced restructuring of its downstream businesses, including the employee-reduction programs for the United States and international operations. Approximately 2,300 employees in the downstream operations are currently expected to be released under these programs. About 2,100 employees have been released through December 31, 2011, with the programs being substantially completed. Substantially all of the remaining employees designated for release under the programs are expected to leave in 2012. About 900 of the affected employees were located in the United States. Refer to Note 23 of the Consolidated Financial Statements, on pages FS-55 through FS-56, for further discussion.

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The company progressed its ongoing effort to concentrate downstream resources and capital on strategic assets. On August 1, 2011, the company completed the sale of its 220,000-barrel-per-day Pembroke Refinery and its fuels marketing and aviation assets in the United Kingdom and Ireland. Through year-end 2011, the company had also completed the sale of 13 U.S. terminals, certain marketing businesses in Africa, LPG storage and distribution operations in China, and its fuels marketing and aviation businesses in 16 countries in the Caribbean and Latin America regions. In 2012, the company also expects to complete the sale of its fuels, finished lubricants and aviation businesses in Spain and certain fuels marketing and aviation businesses in the central Caribbean, pending customary regulatory approvals.

Also in 2011, Caltex Australia Ltd. (CAL), the company s 50 percent-owned affiliate, initiated a review of its refining operations in Australia, which is ongoing. Upon completion, should the review result in a decision to significantly alter the operational role of CAL s refineries, Chevron may recognize a loss that could be significant to net income in any one period.

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. In first quarter 2010, employee-reduction programs were announced for the corporate staffs. As of 2011 year-end, 400 employees from the corporate staffs were released under the programs. Refer to Note 23 of the Consolidated Financial Statements, beginning on page FS-55, for further discussion.

Operating Developments

Key operating developments and other events during 2011 and early 2012 included the following:

Upstream

Australia Chevron and its joint-venture partners reached the final investment decision to proceed with development of the Wheatstone Project. Construction started in late 2011. Chevron holds a 72.1 percent interest in the foundation natural gas processing facilities, which are located at Ashburton North, along the northwest coast of Australia. The company plans to supply natural gas to the foundation project from the Chevron-operated and 90.2 percent-owned Wheatstone and Iago fields. The LNG facilities will also be a destination for third-party natural gas.

Through the end of 2011, Chevron has signed binding Sales and Purchase Agreements with two Asian customers for the delivery of about 60 percent of Chevron s net LNG off-take from the Wheatstone Project. Discussions continue with potential customers to increase sales to 85 to 90 percent of Chevron s net LNG off-take and to sell down equity.

During 2011, the company announced natural gas discoveries at the 50 percent-owned and operated Orthrus Deep prospect in Block WA-24-R, the 50 percent-owned and operated Vos prospect in Block WA-439-P, and the 67 percent-owned and operated Acme West prospect in Block WA-205-P. In January 2012, the company also announced a natural gas discovery at the 50 percent-owned and operated Satyr-3 prospect in Block WA-374-P. These discoveries are expected to contribute to potential expansion at company-operated LNG projects.

Kazakhstan/Russia During 2011, the Caspian Pipeline Consortium began construction on a project to increase the pipeline design capacity by 670,000 barrels per day. The 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.

Nigeria In December 2011, a final investment decision was reached to develop the 40 percent-owned and operated Sonam natural gas field in the Escravos area. The project is designed to deliver 215 million cubic feet of natural gas per day to the domestic market and produce 30,000 barrels of liquids per day.

Thailand In October 2011, the 69.9 percent-owned and operated Platong II natural gas project commenced production. The project ramped up to total average daily production of 377 million cubic feet of natural gas and 11,000 barrels of condensate as of the end of 2011.

United Kingdom In fourth quarter 2011, the company reached a final investment decision for the Clair Ridge Project, located west of the Shetland Islands. Chevron has a 19.4 percent nonoperated working interest in the project.

United States In fourth quarter 2011, a final investment decision was made for the Tubular Bells project in the deepwater Gulf of Mexico. The development includes a 42.9 percent nonoperated working interest in the Tubular

Bells unitized area.

Drilling operations at the 43.8 percent-owned and operated Moccasin prospect resulted in a new discovery of crude oil. The company also drilled a successful appraisal well at the 55 percent-owned Buckskin prospect. Both prospects are in the deepwater Gulf of Mexico.

In February 2011, Chevron acquired Atlas Energy, Inc. The acquisition provided a natural gas resource position in the Marcellus Shale and Utica Shale, primarily located in southwestern Pennsylvania and Ohio. The acquisition also provided a 49 percent interest in Laurel Mountain Midstream, LLC, an affiliate that owns more than 1,000 miles of natural gas gathering lines servicing the Marcellus. In addition, the acquisition provided assets in Michigan, which include Antrim Shale producing assets and approximately

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350,000 total acres in the Antrim and Collingwood/Utica Shale formations. Additional asset acquisitions in 2011 expanded the company s holdings in the Marcellus and Utica to approximately 700,000 and 600,000 total acres, respectively.

Downstream

Africa During 2011, the company completed the sale of certain marketing businesses in five countries in Africa.

Caribbean and Latin America In 2011, the company completed the sale of its fuels marketing and aviation businesses in 16 countries in the Caribbean and Latin America. In fourth quarter 2011, the company signed agreements to sell certain fuels marketing and aviation businesses in the Central Caribbean. The company expects to complete these sales in 2012 following receipt of required local regulatory and government approvals.

Europe In August 2011, the company completed the sale of its refining and marketing assets in the United Kingdom and Ireland, including the Pembroke Refinery.

Singapore In February 2012, the company reached a final investment decision to significantly increase the capacity of the existing additives plant in Singapore.

United States In January 2011, the company announced the final investment decision on a $1.4 billion project to construct a base oil manufacturing facility at the Pascagoula, Mississippi, refinery. The facility is expected to produce approximately 25,000 barrels per day of premium base oil.

Other

Common Stock Dividends The quarterly common stock dividend increased by 8.3 percent in April 2011 and by 3.8 percent in October 2011, to $0.81 per common share, making 2011 the 24th consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program The company purchased $4.25 billion of its common stock in 2011 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 11, beginning on page FS-37, 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	**2011**	2010	2009
Earnings	**$ 6,512**	$ 4,122	$ 2,262

U.S. upstream earnings of $6.51 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.

U.S. upstream earnings of $4.1 billion in 2010 increased $1.9 billion from 2009. Higher prices for crude oil and natural gas increased earnings by $2.1 billion between periods. Partly offsetting these effects were higher operating expenses of $200 million, in part due to the Gulf of Mexico drilling moratorium. Lower exploration expenses were essentially offset by higher tax items and higher depreciation expenses.

The company s average realization for U.S. crude oil and natural gas liquids in 2011 was $97.51 per barrel, compared with $71.59 in 2010 and $54.36 in 2009. The average natural gas realization was $4.04 per thousand cubic feet in 2011, compared with $4.26 and $3.73 in 2010 and 2009, respectively.

Net oil-equivalent production in 2011 averaged 678,000 barrels per day, down 4 percent from 2010 and 5 percent from 2009. Between 2011 and 2010, the decrease in production was associated with normal field declines and maintenance-related downtime. Partially offsetting this decrease were new production from acquisitions in the Marcellus Shale and increases at the Perdido project in the Gulf of Mexico. Natural field declines between 2010 and 2009 were

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mostly offset by increased production from the Tahiti Field. The net liquids component of oil-equivalent production for 2011 averaged 465,000 barrels per day, down 5 percent from 2010 and 4 percent from 2009. Net natural gas production averaged about 1.3 billion cubic feet per day in 2011, down approximately 3 percent from 2010 and about 9 percent from 2009. 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	**2011**	2010	2009
Earnings*	**$ 18,274**	$ 13,555	$ 8,670
*Includes foreign currency effects:	**$ 211**	$ (293)	$ (578)

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 a year earlier.

Earnings of $13.6 billion in 2010 increased $4.9 billion from 2009. Higher prices for crude oil and natural gas increased earnings by $4.3 billion, and an increase in net oil-equivalent production in the 2010 period benefited income by about $1.2 billion. This net benefit was partly offset by higher operating expenses of $500 million. A favorable change in tax items of about $450 million was mostly offset by higher depreciation expenses. The 2009 period included gains of about $500 million on asset sales and tax items related to the Gorgon Project in Australia. Foreign currency effects decreased earnings by $293 million in the 2010 period, compared with a reduction of $578 million a year earlier, primarily reflecting noncash losses on balance sheet remeasurement.

The company s average realization for international crude oil and natural gas liquids in 2011 was $101.53 per barrel, compared with $72.68 in 2010 and $55.97 in 2009. The average natural gas realization was $5.39 per thousand cubic feet in 2011, compared with $4.64 and $4.01 in 2010 and 2009, respectively.

International net oil-equivalent production of 2.0 million barrels per day in 2011 decreased about 3 percent from 2010 and remained relatively flat with 2009. The volumes in 2011 and 2010 include synthetic oil that was reported in 2009 as production from oil sands in Canada. Absent price effects on entitlement volumes, net oil-equivalent production decreased 1 percent in 2011 and increased 5 percent in 2010, when compared with the prior year s production.

The net liquids component of international oil-equivalent production was about 1.4 million barrels per day in 2011, a decrease of approximately 3 percent from 2010 and an increase of approximately 2 percent from 2009. International net natural gas production of 3.7 billion cubic feet per day in 2011 was down 2 percent from 2010 and up 2 percent from 2009.

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	**2011**	2010	2009
Earnings	**$ 1,506**	$ 1,339	$ (121)

U.S. downstream operations earned $1.5 billion in 2011, compared with $1.3 billion in 2010. Earnings benefited by $300 million from improved margins on refined products, $200 million from higher earnings from the 50 percent-owned Chevron Phillips Chemical Company LLC (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.

Earnings increased $1.5 billion in 2010 from 2009. Improved margins on refined products increased earnings by about $550 million. Also contributing to the increase was the nearly $400 million gain on the sale of the company s ownership interest in the Colonial Pipeline Company. Higher earnings from chemicals operations increased earnings by about $300 million, largely from improved margins at CPChem.

Refined product sales of 1.26 million barrels per day in 2011 declined 7 percent, mainly due to lower gasoline, gas oil, and kerosene sales. Sales volumes of refined products were 1.35 million barrels per day in 2010, a decrease of 4 percent from 2009. The decline was mainly in gasoline and jet fuel sales. U.S. branded gasoline sales decreased to 514,000 barrels per day in 2011, representing approximately 10 percent and 17 percent declines from 2010 and 2009, respectively. The decline in 2011, relative to 2010 and 2009, was primarily

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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	**2011**	2010	2009
Earnings*	**$ 2,085**	$ 1,139	$ 594
*Includes foreign currency effects:	**$ (65)**	$ (135)	$ (191)

International downstream earned $2.1 billion in 2011, compared with $1.1 billion in 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 unfavorable mark-to-market effects of derivative instruments of about $180 million. Foreign currency effects decreased earnings by $65 million in 2011, compared with a decrease of $135 million a year earlier.

Earnings of $1.1 billion in 2010 increased $545 million from 2009. Higher margins on the manufacture and sale of gasoline and other refined products increased earnings by about $1.0 billion, and a favorable swing in mark-to-market effects on derivative instruments benefited earnings by about $300 million. Partially offsetting these items was the absence of 2009 gains on asset sales of about $550 million and higher expenses of about $200 million, primarily related to employee reductions and transportation costs. Foreign currency effects reduced earnings by $135 million in 2010, compared with a reduction of $191 million in 2009.

Total refined product sales of 1.69 million barrels per day in 2011 declined 4 percent, 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. International refined product sales volumes of 1.76 million barrels per day in 2010 were 5 percent lower than in 2009, mainly due to asset sales in certain countries in Africa and Latin America.

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	**2011**	2010	2009
Net charges*	**$ (1,482)**	$ (1,131)	$ (922)
*Includes foreign currency effects:	**$ (25)**	$ 5	$ 25

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

Net charges in 2010 increased $209 million from 2009, mainly due to higher expenses for employee compensation and benefits, and higher corporate tax expenses, partly offset by lower provisions for environmental remediation at sites that previously had been closed or sold.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2011**	2010	2009
Sales and other operating revenues	**$ 244,371**	$ 198,198	$ 167,402

Sales and other operating revenues increased in 2011, mainly due to higher prices for crude oil and refined products. Higher 2010 prices resulted in increased revenues compared with 2009.

Millions of dollars	**2011**	2010	2009
Income from equity affiliates	**$ 7,363**	$ 5,637	$ 3,316

Income from equity affiliates increased in 2011 from 2010 mainly due to higher upstream-related earnings from Tengizchevroil (TCO) in Kazakhstan 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.

Income from equity affiliates increased in 2010 from 2009 largely due to higher upstream-related earnings from

TCO in Kazakhstan and Petropiar in Venezuela, principally related to higher prices for crude oil and increased crude oil production. Downstream-related affiliate 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. Improved margins on refined products and a favorable swing in foreign currency effects at GS Caltex in South Korea also contributed to the increase in downstream affiliate earnings in the 2010 period. Refer to Note 12, beginning on page FS-39, for a discussion of Chevron s investments in affiliated companies.

Millions of dollars	**2011**	2010	2009
Other income	**$ 1,972**	$ 1,093	$ 918

Other income of $2.0 billion in 2011 included net gains of approximately $1.5 billion on asset sales. Other income in both 2010 and 2009 included net gains from asset sales of $1.1 billion and $1.3 billion, respectively. Interest income was approximately $145 million in 2011, $120 million in 2010 and $95 million in 2009. Foreign currency effects increased other income by $103 million in 2011, while decreasing other income by $251 million and $466 million in 2010 and 2009, respectively.

Millions of dollars	**2011**	2010	2009
Purchased crude oil and products	**$ 149,923**	$ 116,467	$ 99,653

Crude oil and product purchases in 2011 and 2010 increased by $33.5 billion and $16.8 billion from prior years due to higher prices for crude oil, natural gas and refined products.

Millions of dollars	**2011**	2010	2009
Operating, selling, general and administrative expenses	**$ 26,394**	$ 23,955	$ 22,384

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 reflected a new commercial arrangement that replaced a prior product exchange agreement for upstream operations in Indonesia.

Total expenses in 2010 were about $1.6 billion higher than 2009, primarily due to $600 million of higher fuel expenses; $500 million for employee compensation and benefits; $200 million of increased construction, repair and maintenance expense; and an increase of about $200 million associated with higher tanker charter rates. In addition, charges of $234 million related to employee reductions were included in the 2010 period.

Millions of dollars	**2011**	2010	2009
Exploration expense	**$ 1,216**	$ 1,147	$ 1,342

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

Exploration expenses in 2010 declined from 2009 mainly due to lower amounts for geological and geophysical costs and well write-offs.

Millions of dollars	**2011**	2010	2009

Depreciation, depletion and amortization	**$ 12,911**	$ 13,063	$ 12,110

The decrease in 2011 from 2010 mainly reflected lower production levels and the sale of the Pembroke Refinery, partially offset by higher depreciation rates for certain oil and gas producing fields. The increase in 2010 from 2009 was largely due to higher depreciation rates and higher production for certain oil and gas fields, partly offset by lower impairments.

Millions of dollars	**2011**	2010	2009
Taxes other than on income	**$ 15,628**	$ 18,191	$ 17,591

Taxes other than on income decreased in 2011 from 2010 primarily due to lower import duties in the United Kingdom reflecting the sale of the Pembroke Refinery and other downstream assets, partly offset by higher excise taxes in the company s South Africa downstream operations. Taxes other than on income increased in 2010 from 2009 mainly due to higher excise taxes in Canada and the United Kingdom.

Millions of dollars	**2011**	2010	2009
Interest and debt expense	**$**	$ 50	$ 28

Interest and debt expense, net of capitalized interest, decreased in 2011 from 2010 due to lower average effective interest rates. The increase in 2010 from 2009 was primarily due to slightly higher average effective interest rates.

Millions of dollars	**2011**	2010	2009
Income tax expense	**$ 20,626**	$ 12,919	$ 7,965

Effective income tax rates were 43 percent in 2011, 40 percent in 2010 and 43 percent in 2009. 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. The rate was lower in 2010 than in 2009 primarily due to international upstream effects, including an increased utilization of tax credits, which had a greater impact on the rate than one-time deferred tax benefits and relatively low tax rates on asset sales in 2009. Also, a smaller portion of company income was earned in higher tax rate international upstream jurisdictions in 2010 than in 2009. Finally, foreign currency remeasurement impacts caused a reduction in the effective tax rate between periods.

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Selected Operating Data[1,2]

	2011	2010	2009
U.S. Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	**465**	489	484
Net Natural Gas Production (MMCFPD)[3]	**1,279**	1,314	1,399
Net Oil-Equivalent Production (MBOEPD)	**678**	708	717
Sales of Natural Gas (MMCFPD)	**5,836**	5,932	5,901
Sales of Natural Gas Liquids (MBPD)	**15**	22	17
Revenues From Net Production			
Liquids ($/Bbl)	**$ 97.51**	$ 71.59	$ 54.36
Natural Gas ($/MCF)	**$ 4.04**	$ 4.26	$ 3.73
International Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)[4]	**1,384**	1,434	1,362
Net Natural Gas Production (MMCFPD)[3]	**3,662**	3,726	3,590
Net Oil-Equivalent			
Production (MBOEPD)[5]	**1,995**	2,055	1,987
Sales of Natural Gas (MMCFPD)	**4,361**	4,493	4,062
Sales of Natural Gas Liquids (MBPD)	**24**	27	23
Revenues From Liftings			
Liquids ($/Bbl)	**$ 101.53**	$ 72.68	$ 55.97
Natural Gas ($/MCF)	**$ 5.39**	$ 4.64	$ 4.01
Worldwide Upstream			
Net Oil-Equivalent Production			
(MBOEPD)[3,5]			
United States	**678**	708	717
International	**1,995**	2,055	1,987
Total	**2,673**	2,763	2,704
U.S. Downstream			
Gasoline Sales (MBPD)[6]	**649**	700	720
Other Refined Product Sales (MBPD)	**608**	649	683
Total Refined Product Sales (MBPD)	**1,257**	1,349	1,403
Sales of Natural Gas Liquids (MBPD)	**146**	139	144
Refinery Input (MBPD)	**854**	890	899
International Downstream			
Gasoline Sales (MBPD)[6]	**447**	521	555
Other Refined Product Sales (MBPD)	**1,245**	1,243	1,296

Total Refined Product Sales (MBPD)[7]	**1,692**	1,764	1,851
Sales of Natural Gas Liquids (MBPD)	**63**	78	88
Refinery Input (MBPD)	**933**	1,004	979

[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	**69**	62	58
International	**513**	475	463
[4] Includes: Canada synthetic oil	**40**	24	
Venezuela affiliate synthetic oil	**32**	28	
[5] Includes Canada oil sands			26
[6] Includes branded and unbranded gasoline.			
[7] Includes sales of affiliates (MBPD):	**556**	562	516

Liquidity and Capital Resources

Cash, cash equivalents, time deposits and marketable securities Total balances were $20.1 billion and $17.1 billion at December 31, 2011 and 2010, respectively. Cash provided by operating activities in 2011 was $41.1 billion, compared with $31.4 billion in 2010 and $19.4 billion in 2009. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.5 billion, $1.4 billion and $1.7 billion in 2011, 2010 and 2009, respectively. Cash provided by operating activities during 2011 was more than sufficient to fund the $27.4 billion cash component of the company s capital and exploratory program and pay $6.1 billion of dividends to shareholders. In addition, the company completed the $4.5 billion acquisition of Atlas Energy, Inc., funded from the company s operating cash flows. Cash provided by investing activities included proceeds and deposits related to asset sales of $3.5 billion in 2011, $2.0 billion in 2010, and $2.6 billion in 2009.

Restricted cash of $1.2 billion and $855 million associated with various capital-investment projects, acquisitions pending tax deferred exchanges, and Upstream abandonment activities at December 31, 2011 and 2010, 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 approximately $6.1 billion in 2011, $5.7 billion in 2010 and $5.3 billion in 2009. In October 2011, the company increased its quarterly dividend by 3.8 percent to 81 cents per common share. This followed an increase of 8.3 percent announced in second quarter 2011.

Capital and Exploratory Expenditures

			2011			2010			2009
Millions of dollars	U.S.	Int l.	Total	U.S.	Int l.	Total	U.S.	Int l.	Total
Upstream[1]	**$ 8,318**	**$ 17,554**	**$ 25,872**	$ 3,450	$ 15,454	$ 18,904	$ 3,294	$ 15,002	$ 18,296
Downstream	**1,461**	**1,150**	**2,611**	1,456	1,096	2,552	2,087	1,449	3,536
All Other	**575**	**8**	**583**	286	13	299	402	3	405
Total	**$ 10,354**	**$ 18,712**	**$ 29,066**	$ 5,192	$ 16,563	$ 21,755	$ 5,783	$ 16,454	$ 22,237
Total, Excluding Equity in Affiliates	**$ 10,077**	**$ 17,294**	**$ 27,371**	$ 4,934	$ 15,433	$ 20,367	$ 5,558	$ 15,094	$ 20,652

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

Debt and capital lease obligations Total debt and capital lease obligations were $10.2 billion at December 31, 2011, down from $11.5 billion at year-end 2010.

The $1.3 billion decrease in total debt and capital lease obligations during 2011 included the early redemption of a $1.5 billion bond due to mature in March 2012. 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 $5.9 billion at December 31, 2011, compared with $5.6 billion at year-end 2010. Of these amounts, $5.6 billion and $5.4 billion were reclassified to long-term at the end of each period, respectively. At year-end 2011, settlement of these obligations was not expected to require the use of working capital in 2012, 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, 2011, 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, 2011. In addition, the company has an automatic shelf registration statement that expires in March 2013 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 and Poor s Corporation and Aa1 by Moody s Investors Service. The company s U.S. commercial paper is rated A-1+ by Standard and 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 2011, the company purchased 42.3 million common shares for $4.25 billion. From the inception of the program through 2011, the company had purchased 51.1 million shares for $5.0 billion.

Capital and exploratory expenditures Total expenditures for 2011 were $29.1 billion, including $1.7 billion for the company s share of equity-affiliate expenditures.
In 2010 and 2009, expenditures were $21.8 billion and $22.2 billion, respectively, including the company s share of affiliates expenditures of $1.4 billion and $1.6 billion, respectively.

Of the $29.1 billion of expenditures in 2011, 89 percent, or $25.9 billion, was related to upstream activities. Approximately 87 percent and 80 percent were expended for upstream operations in 2010 and 2009. International upstream accounted for about 68 percent of the worldwide upstream investment in 2011, about 82 percent in 2010 and about 80 percent in 2009. These amounts exclude the acquisition of Atlas Energy, Inc. in 2011.

The company estimates that in 2012 capital and exploratory expenditures will be $32.7 billion, including $3.0 billion of spending

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by affiliates. Approximately 87 percent of the total, or $28.5 billion, is budgeted for exploration and production activities. Approximately $22.3 billion, or 78 percent, of this amount is for projects outside the United States. Spending in 2012 is primarily focused on major development projects in Angola, Australia, Brazil, Canada, China, Kazakhstan, Nigeria, 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 2012 is estimated at $3.6 billion, with about $2.1 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and South Korea, expansion of additives production capacity in Singapore, and chemicals projects in the United States and Saudi Arabia.

Investments in technology, power generation and other corporate businesses in 2012 are budgeted at $600 million.

Noncontrolling interests The company had noncontrolling interests of $799 million and $730 million at December 31, 2011 and 2010, respectively. Distributions to noncontrolling interests totaled $71 million and $72 million in 2011 and 2010, respectively.

Pension Obligations Information related to pension plan contributions is included on page FS-54 in Note 21 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		
	2011	2010	2009
Current Ratio	**1.6**	1.7	1.4
Interest Coverage Ratio	**165.4**	101.7	62.3
Debt Ratio	**7.7%**	9.8%	10.3%

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 2011, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $9.0 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 2011 was higher than 2010 and 2009 due to higher before-tax income.

Debt Ratio total debt as a percentage of total debt plus Chevron Corporation Stockholders Equity, which indicates the company s leverage. The decrease between 2011 and 2010 was due to lower debt and a higher Chevron Corporation stockholders equity balance. The decrease between 2010 and 2009 was due to a higher Chevron Corporation stockholders equity balance.