CHEVRON CORP
Form 10-K
February 24, 2011

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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, 2010**
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. (Check one):

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 $136,438,881,628 (As of June 30, 2010)

Number of Shares of Common Stock outstanding as of February 18, 2011 2,007,449,583

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2011 Annual Meeting and 2011 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company s 2011 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 32 through 34 in this report. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

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 of crude oil into petroleum products; marketing of crude oil and refined products; transporting of crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lubricant additives.

A list of the company s major subsidiaries is presented on pages E-4 and E-5. As of December 31, 2010, Chevron had approximately 62,000 employees (including about 3,900 service station employees). Approximately 30,000 employees (including about 3,600 service station employees), or 48 percent, were employed in U.S. operations.

Overview of Petroleum Industry

Petroleum industry operations and profitability are influenced by many factors, and individual petroleum companies have little control over some of them. Governmental policies, particularly in the areas of taxation, energy and the environment have a significant impact on petroleum activities, regulating how companies are structured and where and how companies conduct their operations and formulate their products and, in some cases, limiting their profits directly. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand for these commodities. However, some governments impose price controls on refined products such as gasoline or diesel fuel. 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. Seasonality is not a primary driver of changes in the company s quarterly earnings during the year.

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-10 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.

Chevron 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 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, 2010, and assets as of the end of 2010 and 2009 for the United States and the company s international geographic areas are in Note 11 to the Consolidated Financial Statements beginning on page FS-41. 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-43 through FS-45.

Capital and Exploratory Expenditures

Total expenditures for 2010 were $21.8 billion, including $1.4 billion for the company s share of equity-affiliate expenditures. In 2009 and 2008, expenditures were $22.2 billion and $22.8 billion, respectively, including the company s share of affiliates expenditures of $1.6 billion in 2009 and $2.3 billion in 2008.

Of the $21.8 billion in expenditures for 2010, 87 percent, or $18.9 billion, was related to upstream activities. Approximately 80 percent was expended for upstream operations in 2009 and 2008. International upstream accounted for about 82 percent of the worldwide upstream investment in 2010, more than 80 percent in 2009 and about 70 percent in 2008, reflecting the company s continuing focus on opportunities available outside the United States.

In 2011, the company estimates capital and exploratory expenditures will be $26.0 billion, including $2.0 billion of spending by affiliates. Approximately 85 percent of the total, or $22.6 billion, is budgeted for exploration and production activities, with $17.2 billion of that amount for projects outside the United States. Acquisition costs associated with the announced purchase of Atlas Energy, Inc., are not included.

Refer also to a discussion of the company s capital and exploratory expenditures on page FS-13.

Upstream

The table on the following page summarizes the net production of liquids and natural gas for 2010 and 2009 by the company and its affiliates. Worldwide oil-equivalent production, including volumes from synthetic oil in 2010 and oil sands in 2009, was 2.763 million barrels per day, up about 2 percent from 2009. The increase was mainly associated with the start-up and ramp-up of several major capital projects the expansion at Tengiz in Kazakhstan, the Tahiti Field in the U.S. Gulf of Mexico, Frade in Brazil, Agbami in Nigeria, and Tombua-Landana and Mafumeira Norte in Angola. Normal field declines and the impact of higher prices on cost-recovery volumes and other contractual provisions decreased net production from last year s comparative period. Refer to the Results of Operations section beginning on page FS-7 for a detailed discussion of the factors explaining the 2008 2010 changes in production for crude oil and natural gas liquids, and natural gas.

The company estimates its average worldwide oil-equivalent production in 2011 will be approximately 2.790 million barrels per day based on the average West Texas Intermediate crude oil price of $79 per barrel in 2010. This estimate is subject to many factors and uncertainties, including additional quotas that may be imposed by OPEC, price effects on production volumes calculated under production-sharing and variable-royalty provisions of certain agreements, 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 9, for a discussion of the company s major crude oil and natural gas development projects.

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Net Production of Crude Oil and Natural Gas Liquids and Natural Gas[1,2,3]

	Oil-Equivalent (Thousands of Barrels per Day)		Components of Oil-Equivalent: Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day)		Natural Gas (Millions of Cubic Feet per Day)	
	2010	2009	2010	2009	2010	2009
United States	**708**	717	**489**	484	**1,314**	1,399
Other Americas:						
Canada	**54**	28	**53**	27	**4**	4
Colombia	**41**	41			**249**	245
Trinidad and Tobago	**38**	34	**1**	1	**223**	199
Argentina	**32**	38	**31**	33	**5**	27
Brazil	**24**	2	**23**	2	**7**	
Total Other Americas	**189**	143	**108**	63	**488**	475
Africa:						
Nigeria	**253**	232	**239**	225	**86**	48
Angola	**161**	150	**152**	141	**52**	49
Chad	**28**	27	**27**	26	**6**	5
Republic of the Congo	**25**	21	**23**	19	**10**	13
Democratic Republic of the Congo	**2**	3	**2**	3	**1**	1
Total Africa	**469**	433	**443**	414	**155**	116
Asia:						
Indonesia	**226**	243	**187**	199	**236**	268
Thailand	**216**	198	**70**	65	**875**	794
Partitioned Zone (PZ)[4]	**98**	105	**94**	101	**23**	21
Bangladesh	**69**	66	**2**	2	**404**	387
Kazakhstan	**64**	69	**39**	42	**149**	161
Azerbaijan	**30**	30	**28**	28	**11**	10
Philippines	**25**	27	**4**	4	**124**	137
China	**20**	19	**18**	17	**13**	16
Myanmar	**13**	13			**81**	76
Total Asia	**761**	770	**442**	458	**1,916**	1,870
Australia	**111**	108	**34**	35	**458**	434
Europe:						
United Kingdom	**97**	110	**64**	73	**194**	222
Denmark	**51**	55	**32**	35	**116**	119

Netherlands	**8**	9	**2**	2	**35**	41
Norway	**3**	5	**3**	5	**1**	1
Total Europe	**159**	179	**101**	115	**346**	383
Total Consolidated Operations	**2,397**	2,350	**1,617**	1,569	**4,677**	4,677
Equity Affiliates[5]	**366**	328	**306**	277	**363**	312
Total Including Affiliates[6]	**2,763**	2,678	**1,923**	1,846	**5,040**	4,989

[1] 2009 conformed to 2010 geographic presentation.

[2] Excludes Athabasca oil sands production, net: 26 26

[3] Includes synthetic oil: Canada, net **24** **24**
Venezuelan affiliate, net **28** **28**

[4] Located between Saudi Arabia and Kuwait.

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

[6] Volumes include natural gas consumed in operations of 537 million and 521 million cubic feet per day in 2010 and 2009, respectively. Total as sold natural gas volumes were 4,503 million and 4,468 million cubic feet per day for 2010 and 2009, respectively.

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Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-71 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 2010, 2009 and 2008.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2010 for the company and its affiliates:

Productive Oil and Gas Wells[1] at December 31, 2010

	Productive[2,3] Oil Wells		Productive[2] Gas Wells	
	Gross	Net	Gross	Net
United States	49,455	32,462	11,637	5,720
Other Americas	640	487	49	25
Africa	2,387	798	17	7
Asia	12,420	10,693	3,050	1,920
Australia	753	422	64	11
Europe	325	101	156	37
Total Consolidated Companies	65,980	44,963	14,973	7,720
Equity in Affiliates	1,135	404	7	2
Total Including Affiliates	67,115	45,367	14,980	7,722
Multiple completion wells included above:	901	590	370	303

[1] Includes wells producing or capable of producing and injection wells temporarily functioning as producing wells. Wells that produce both crude oil and natural gas are classified as oil wells.
[2] Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned wells and the sum of the company s fractional interests in gross wells.
[3] Canadian synthetic oil is not produced through wells and therefore is not represented in the table above.

Reserves

Refer to Table V beginning on page FS-71 for a tabulation of the company s proved net crude oil and natural gas reserves by geographic area, at the beginning of 2008 and each year-end from 2008 through 2010. A discussion of reserves governance and major changes to proved reserves by geographic area for the three-year period ending December 31, 2010 is summarized in the discussion for Table V. Discussion is also provided beginning on page FS-71 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. During 2010, the company provided crude oil and natural gas reserves estimates for 2009 to the Department of Energy, Energy Information Administration (EIA) that agree with the 2009 reserve volumes in Table V. This reporting fulfilled the requirement that such estimates be consistent with, and not differ more than 5 percent from, the information furnished to the Securities and Exchange Commission (SEC) in the company s 2009 Annual Report on Form 10-K. During 2011, the company will file estimates of crude oil and natural gas reserves with the Department of Energy, EIA, consistent with the 2010 reserve data reported in Table V.

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The net proved reserve balances at the end of each of the three years 2008 through 2010 are shown in the following table.

Net Proved Reserves at December 31

	2010	2009	2008
Liquids Millions of barrels			
Consolidated Companies	**4,270**	4,610	4,735
Affiliated Companies	**2,233**	2,363	2,615
Natural Gas Billions of cubic feet			
Consolidated Companies	**20,755**	22,153	19,022
Affiliated Companies	**3,496**	3,896	4,053
Total Oil-Equivalent Millions of barrels			
Consolidated Companies	**7,729**	8,303	7,905
Affiliated Companies	**2,816**	3,012	3,291

Acreage

At December 31, 2010, the company owned or had under lease or similar agreements undeveloped and developed crude oil and natural gas properties located throughout the world. The geographical distribution of the company s acreage is shown in the following table.

Acreage[1,2] at December 31, 2010
(Thousands of Acres)

	Undeveloped[3]		Developed[3]		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States	5,799	4,625	6,868	4,232	12,667	8,857
Other Americas	28,039	16,405	1,197	357	29,236	16,762
Africa	8,176	4,022	3,339	1,373	11,515	5,395
Asia	48,480	25,500	5,420	2,764	53,900	28,264
Australia	14,945	6,958	1,706	365	16,651	7,323
Europe	4,097	2,408	632	134	4,729	2,542
Total Consolidated Companies	109,536	59,918	19,162	9,225	128,698	69,143
Equity in Affiliates	636	299	263	106	899	405
Total Including Affiliates	110,172	60,217	19,425	9,331	129,597	69,548

[1] Gross acreage includes the total number of acres in all tracts in which the company has an interest. Net acreage includes wholly owned interests and the sum of the company s fractional interests in gross acreage.

[2] Table does not include mining acreage associated with synthetic oil production in Canada. At year-end 2010, such undeveloped gross and net acreage totaled 222 and 31, respectively. Developed gross and net acreage associated with Canadian synthetic oil operations totaled 48 and 9, respectively. Developed acreage is acreage associated with productive mines. Undeveloped acreage is acreage on which mines have not been established and that may contain undeveloped proved reserves.

[3] Developed acreage is spaced or assignable to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to permit commercial production and that may contain proved undeveloped reserves. The gross undeveloped acres that will expire in 2011, 2012 and 2013 if production is not established by certain required dates are 6,458, 2,672 and 5,996, respectively.

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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 253 billion cubic feet of natural gas through 2013. 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 index and fixed-price contracts.

Outside the United States, the company is contractually committed to deliver a total of 953 billion cubic feet of natural gas from 2011 through 2013 from 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-66 for details associated with the company s development expenditures and costs of proved property acquisitions for 2010, 2009 and 2008.

The table below 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, 2010. A development well is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Development Well Activity

	Wells Drilling at 12/31/10[3]		Net Wells Completed[1,2]					
			2010		2009		2008	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**62**	**32**	**634**	**7**	582	3	846	4
Other Americas	**4**	**2**	**32**		36		35	
Africa	**12**	**5**	**33**		40		33	
Asia	**55**	**21**	**445**	**15**	580	10	665	1
Australia								
Europe	**5**		**4**		7		6	
Total Consolidated Companies	**138**	**60**	**1,148**	**22**	1,245	13	1,585	5
Equity in Affiliates	**2**	**1**	**8**		6		16	
Total Including Affiliates	**140**	**61**	**1,156**	**22**	1,251	13	1,601	5

[1] 2009 and 2008 conformed to 2010 geographic presentation.

[2] Indicates the fractional number of wells completed during the year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency.

[3] Represents wells in the process of drilling, including wells for which drilling was not completed and which were temporarily suspended at the end of 2010. Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned wells and the sum of the company s fractional interests in gross wells.

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, 2010. 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 12/31/10[3]		Net Wells Completed[1,2]					
			2010		2009		2008	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**5**	**2**	**1**	**1**	4	5	8	2
Other Americas	**2**	**1**		**1**	1	2	39	2
Africa	**5**	**2**	**1**		2	1	2	1
Asia	**9**	**4**	**5**	**5**	9	1	9	2
Australia	**1**	**1**	**5**	**2**	4	2	4	
Europe							1	
Total Consolidated Companies	**22**	**10**	**12**	**9**	20	11	63	7
Equity in Affiliates								
Total Including Affiliates	**22**	**10**	**12**	**9**	20	11	63	7

1 2009 and 2008 conformed to 2010 geographic presentation.

2 Indicates the fractional number of wells completed during the year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency. Some exploratory wells are not drilled with the intention of producing from the well bore. In such cases, completion refers to the completion of drilling. Further categorization of productive or dry is based on the determination as to whether hydrocarbons in a sufficient quantity were found to justify completion as a producing well, whether or not the well is actually going to be completed as a producer.

3 Represents wells that are in the process of drilling but have been neither abandoned nor completed as of the last day of the year, including wells for which drilling was not completed and which were temporarily suspended at the end of 2010. Gross wells include the total number of wells in which the company has an interest. Net wells include wholly owned wells and the sum of the company s fractional interests in gross wells.

Refer to Table I on page FS-66 for detail of the company s exploration expenditures and costs of unproved property acquisitions for 2010, 2009 and 2008.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron s 2010 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-25.

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 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.

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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, Louisiana, Texas, New Mexico, the Rocky Mountains and Alaska. Average net oil-equivalent production in the United States during 2010 was 708,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2010, average net oil-equivalent production was 199,000 barrels per day, composed of 178,000 barrels of crude oil, 96 million cubic feet of natural gas and 5,000 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 2010 for the company s combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region was 260,000 barrels per day. The daily oil-equivalent production was composed of 169,000 barrels of crude oil, 445 million cubic feet of natural gas and 17,000 barrels of natural gas liquids.

In April 2010, an accident occurred at the BP-operated Macondo prospect in the deepwater Gulf of Mexico, resulting in a loss of life, the sinking of the rig and a significant oil spill. Chevron was not a participant in the well. Subsequent to the event, the U.S. Department of the Interior placed a moratorium on the drilling of wells using subsea blowout preventers (BOPs) or surface BOPs on a floating facility in the Gulf of Mexico and the Pacific regions. During the moratorium, Chevron participated in a number of industry efforts to identify opportunities to improve industry standards in prevention, intervention and spill response. In July 2010, Chevron and several other major energy companies announced plans to build and deploy a rapid response system that will be available to capture and contain oil in the unlikely event of a potential future well blowout in the deepwater Gulf of Mexico. In October 2010, the Secretary of the Interior lifted the moratorium on deepwater drilling activity, provided that operators certify compliance with new rules and requirements. The drilling moratorium and the ensuing slowdown in issuing drilling permits have resulted in delays in shallow water drilling activity, delayed drilling of exploratory deepwater wells and impacted development drilling on both operated and nonoperated projects in the Gulf of Mexico. In addition, the company s net oil-equivalent production in the Gulf of Mexico was reduced by about 10,000 barrels per day for the full year.

Chevron was engaged in various exploration and development activities in the deepwater Gulf of Mexico during 2010. First oil at the Perdido Regional Development was achieved in first quarter 2010. The development includes a 37.5 percent nonoperated working interest in a producing host facility in Alaminos Canyon designed to service multiple nonoperated fields, including Chevron s 33.3 percent-owned Great White, 60 percent-owned Silvertip and 57.5 percent-owned Tobago. The development has an expected production life of approximately 25 years.

The final investment decision was made for the Tahiti 2 waterflood project in third quarter 2010. Tahiti 2 is the second development phase for the 58 percent-owned and operated Tahiti Field and is designed to increase recovery and maintain production near the facility capacity of 125,000 barrels of oil per day. The project includes three water injection wells, two additional production wells and the facilities required to deliver water to the injection wells. Drilling began on the first water injection well in September 2010. The field has an estimated production life of 30 years. As of the end of 2010, proved reserves had not been recognized for this second development phase of the Tahiti Field.

During 2010, work continued at the 60 percent-owned and operated Big Foot discovery. The project completed front-end engineering and design (FEED) in June 2010 and a final investment decision was made in December 2010. Total maximum production is expected to reach 79,000 barrels of oil-equivalent per day. First production is expected in 2014, and at the end of 2010 proved reserves had not been recognized. The field has an estimated production life of 20 years.

The topsides modifications to the host facility of the Caesar/Tonga Project were completed in 2010. The company has a 20.3 percent nonoperated working interest in the Caesar and Tonga partnerships unitized area. Development plans include a total of four wells and a subsea tieback to a nearby third-party production facility. Work on the subsea system, commissioning of the topsides and the initial well completion program carried over into 2011. A recent mechanical issue involving the production riser system has delayed first production. Proved reserves have been recognized for the project.

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, following the acquisition of an additional 9.8 percent equity interest in St. Malo in March 2010. Both fields are company operated. The FEED activities initiated in 2009 continued into 2010, and a final investment decision was achieved in October 2010. The facility is planned to have an initial design capacity of 177,000 barrels of oil-equivalent per day. 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. At the end of 2010, proved reserves had not been recognized.

Assessment of development concepts continued in 2010 for the appraised resource potential on the Mad Dog II Development Project, in which the company has a 15.6 percent nonoperated working interest. These areas are outside the drilling radius of the existing floating production facility. A decision on the development concept, followed by the project moving into the FEED stage, is expected to occur in the second-half 2011. At the end of 2010, proved reserves had not been recognized.

Studies to screen and evaluate future development alternatives in the Tubular Bells unitized area, in which the company has a 30 percent nonoperated working interest, continued into 2010, and a subsea tieback to a planned third-party host facility was selected as the development concept. FEED commenced in fourth quarter 2010 with a final investment decision expected in second quarter 2011. At the end of 2010, proved reserves had not been recognized.

Deepwater exploration activities in 2010 included participation in five exploratory wells two wildcat, two appraisal and one delineation. Drilling operations on two exploratory wells were interrupted and stopped in second quarter 2010 as a result of the deepwater drilling moratorium in the Gulf of Mexico, including drilling of the first appraisal well at the 55 percent-owned and operated Buckskin discovery. The first appraisal well at Knotty Head was completed in March 2010 and interpretation of well results continued into 2011. Chevron has a 25 percent nonoperated working interest in the Knotty Head discovery. At the end of 2010, the company had not recognized proved reserves for any of these exploration projects.

During 2010, the company added 15 new leases to its deepwater portfolio as a result of bid awards stemming from a Gulf of Mexico lease sale early in the year.

Besides the activities connected with the development and exploration projects in the Gulf of Mexico, the company also has contracted capacity of 1 billion cubic feet per day at the third-party Sabine Pass liquefied natural gas (LNG) regasification terminal in Louisiana to enable the import of natural gas for the North America market. Chevron has also contracted 1.6 billion cubic feet per day of capacity 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 an interconnect with 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.

Outside California and the Gulf of Mexico, the company manages operations across the mid-continental United States and Alaska. During 2010, the company s U.S. production outside California and the Gulf of Mexico averaged 249,000 net oil-equivalent barrels per day, composed of 91,000 barrels of crude oil, 773 million cubic feet of natural gas and 29,000 barrels of natural gas liquids.

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The company continues to pursue its interest in tight carbonate oil resources in West Texas in the Wolfcamp and associated formations where advances in drilling and completion technologies have opened up widespread targets such as the 100 percent-owned and operated Lupin Project, where first oil was realized in mid-2010. Additional production growth is expected from both operated and nonoperated interests in these formations in future years through continued use of these advances in drilling and completion technologies. The company also continued the appraisal of the Haynesville shale gas play in East Texas.

In the Piceance Basin in northwestern Colorado, the company continued development of its 100 percent-owned and operated natural gas field. Development drilling and completion activities continued in 2010, with 115 completed wells available to supply natural gas to the central processing facility. The 2010 work plan focused on optimization of the existing wells and facilities, completion of previously drilled wells, and designing a pilot to test liquefied petroleum gas (LPG) as an alternative fracture fluid beginning in fourth quarter 2011. Future work is expected to be completed in multiple stages. The full development plan includes drilling more than 2,000 wells from multi-well pads over the next 30 to 40 years. Proved reserves for subsequent stages of the project had not been recognized at year-end 2010.

In February 2011, Chevron acquired Atlas Energy, Inc. The acquisition provides an attractive natural gas resource position in the Appalachian basin, primarily located in southwestern Pennsylvania, and consists of approximately 850,000 total acres of Marcellus Shale and Utica Shale. The acquisition provides 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. The acquisition also provides assets in Michigan, which include Antrim Shale producing assets and approximately 380,000 total acres in the Antrim and Collingwood/Utica Shale.

b) Other Americas

Other Americas is composed of Canada, Greenland, Argentina, Brazil, Colombia, Trinidad and Tobago, and Venezuela. Net oil-equivalent production from these countries averaged 247,000 barrels per day during 2010, 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 and 26.6 percent in the Hebron Field, both offshore eastern Canada, and 20 percent in both the Athabasca Oil Sands Project (AOSP) and the AOSP Expansion 1 Project. Average net oil-equivalent production during 2010 was 54,000 barrels per day, composed of 53,000 barrels of crude oil, synthetic oil and natural gas liquids and 4 million cubic feet of natural gas.

The company s 2010 production from the Hibernia Field averaged 28,000 barrels per day. The working interest owners are pursuing development of the Hibernia Southern Extension (HSE) unitized blocks. Binding agreements were signed in February 2010 with the government of Newfoundland and Labrador on the development of the HSE unitized area, providing Chevron with a 23.6 percent nonoperated working interest. First production from the HSE unitized area is expected in late 2011. At the end of 2010, proved reserves had not been recognized for the unitized blocks.

FEED commenced in third quarter 2010 for the development of the heavy-oil Hebron Field. The project has an expected economic life of 30 years. At the end of 2010, proved reserves had not been recognized for this project.

At AOSP, the company s production of synthetic oil averaged 24,000 barrels per day during 2010, including first production from the Jackpine Mine in third quarter 2010 as a result of AOSP Expansion 1 Project activities. The project is expected to increase total daily maximum design capacity by 100,000 barrels, to more than 255,000 barrels per day in early 2011. 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. Expansion of the Scotford Upgrader, also part of the AOSP Expansion 1 Project, is expected to be completed in first-half 2011.

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The company acquired a new exploration lease in the Beaufort Sea in 2010 and also holds other exploration licenses and leases in the Orphan Basin offshore Atlantic Canada, the Mackenzie Delta region of the Northwest Territories and the Beaufort Sea region of Canada s Arctic, including a 34 percent nonoperated working interest in the offshore Amauligak discovery. In addition, through 2010 the company acquired approximately 200,000 acres in Alberta s Duvernay formation to explore for shale gas and plans to commence an appraisal drilling program in the second-half 2011. At the end of 2010, proved reserves had not been recognized for any of these exploration areas.

Greenland: Evaluation of the 2-D seismic survey acquired over License 2007/26 in Block 4 offshore West Greenland commenced in 2010 and is planned to continue into 2011. Chevron has a 29.2 percent nonoperated working interest in this exploration license.

Argentina: Chevron holds operated interests in five concessions in the Neuquen Basin. Working interests range from 18.8 percent to 100 percent. Net oil-equivalent production in 2010 averaged 32,000 barrels per day, composed of 31,000 barrels of crude oil and natural gas liquids and 5 million cubic feet of natural gas. The company also holds a 14 percent interest in the Oleoductos del Valle S.A. pipeline. In 2010, Chevron sold its interest in the Puesto Prado, Las Bases and El Sauce fields in the Neuquen Basin.

Brazil: Chevron holds working interests in three deepwater blocks in the Campos Basin. Chevron also holds a nonoperated working interest in one deepwater block in the Santos Basin. Net oil-equivalent production in 2010 averaged 24,000 barrels per day.

During 2010, development drilling continued at the 51.7 percent-owned and operated Frade Field, located in the Campos Basin. Further development drilling is expected to add five development wells and three injection wells to the field by the end of 2011. 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. A final investment decision for the Papa-Terra project was made in January 2010. Major construction contracts were awarded in 2010, and development drilling is expected to begin in the second-half 2011. The facility is expected to produce up to 140,000 barrels of crude oil per day. First production is expected in 2013. Evaluation of the field development concept for Maromba continued into 2011. At the end of 2010, proved reserves had not been recognized for these projects.

In the Santos Basin, evaluation of investment options continued into 2011 for the 20 percent-owned and partner-operated Atlanta and Oliva fields. At the end of 2010, proved reserves had not been recognized for these deepwater fields.

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 from a fixed-fee, Build-Operate-Maintain-Transfer agreement based on prior Chuchupa capital contributions. During 2010, the company conducted a seismic survey of the offshore, near-shore and onshore development areas. Daily net production averaged 249 million cubic feet of natural gas in 2010.

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. Chevron also holds a 50 percent operated interest in the Manatee Area of Block 6(d). Net production in 2010 averaged 223 million cubic feet of natural gas per day. In 2010, a Loran/Manatee field-specific treaty was signed by the governments of Trinidad and Tobago and Venezuela related to the company s 2005 successful exploratory well in the Manatee Area of Block 6(d). At the end of 2010, proved reserves had not been recognized for this field.

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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 average net oil-equivalent production during 2010 from these operations, including synthetic oil from Hamaca, was 58,000 barrels per day, composed of 54,000 barrels of crude oil, synthetic oil and natural gas liquids and 25 million cubic feet of natural gas.

In February 2010, a Chevron-led consortium was selected to participate in a heavy-oil project in three blocks within the Carabobo Area of eastern Venezuela s Orinoco Belt. A joint operating company, Petroindependencia, was formed in May 2010, and work toward commercialization of the Carabobo 3 Project was initiated. The consortium holds a combined 40 percent interest in the project, with Petróleos de Venezuela, S.A. (PDVSA), Venezuela s national crude oil and natural gas company, holding the remaining interest. Chevron s interest in the project is 34 percent.

The company operates in two exploratory blocks in the Plataforma Deltana area offshore eastern Venezuela, with working interests of 60 percent in Block 2 and 100 percent in Block 3. Chevron also holds a 100 percent operated interest in the Cardon III exploratory block, located north of Lake Maracaibo in the Gulf of Venezuela. PDVSA has the option to increase its ownership in each of the three company-operated blocks up to 35 percent upon declaration of commerciality. In Block 2, which includes the Loran Field, a Declaration of Commerciality was accepted by the Venezuelan government in March 2010. The Loran Field in Block 2 is projected to provide the initial natural gas supply for a planned Delta Caribe liquefied natural gas plant, Venezuela s first LNG project. Chevron has a 10 percent nonoperated working interest in the LNG facility. At the end of 2010, proved reserves had not been recognized in these exploratory blocks.

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 469,000 barrels per day during 2010.

Angola: Chevron holds company-operated working interests in offshore Blocks 0 and 14 and nonoperated working interests in offshore Block 2 and the onshore Fina Sonangol Texaco (FST) area. Net production from these operations in 2010 averaged 161,000 barrels of oil-equivalent per day.

The company operates the 39.2 percent-owned Block 0, which averaged 116,000 barrels per day of net liquids production in 2010. The Block 0 concession extends through 2030.

Development of the Mafumeira Field in Block 0 continued in 2010. A development drilling program was completed in the northern section and achieved maximum total crude oil and condensate production of 57,000 barrels per day in fourth quarter 2010.

FEED started in January 2010 on Mafumeira Sul, a project to develop the southern portion of the Mafumeira Field. A final investment decision is expected in fourth quarter 2011. 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 2010, no proved reserves had been recognized for the Mafumeira Sul project.

In the Greater Vanza/Longui Area of Block 0, development concept selection studies continued in 2010 with the start of FEED planned for second quarter 2011. FEED activities continued on the south extension of the N Dola field development

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with a final investment decision expected in fourth quarter 2011. At year-end 2010, no proved reserves had been recognized for these projects.

In Block 0, the Area A gas management projects are designed to eliminate routine flaring of natural gas by injecting excess natural gas into various reservoirs. Three of the four projects are in service and have reduced flaring by approximately 65 million cubic feet per day, as of year-end 2010. The Malongo Flare and Relief Modification Project is scheduled for start-up in fourth quarter 2011. In Area B, work continued during the year on the Nemba Enhanced Secondary Recovery and Flare Reduction Project. The first stage of the project was planned to be completed with the start of gas injection in second quarter 2011 on the existing South Nemba platform. The next stage, which includes completion of a new platform and additional compression facilities, is scheduled to begin gas injection in 2014.

Also in Block 0, a two-well exploration and appraisal program was completed in 2010. The first well, completed in February 2010, was successful and development opportunities are being evaluated. The second well, completed in June 2010, was not successful. Two additional exploratory wells are planned for 2011.

In the 31 percent-owned Block 14, net production in 2010 averaged 34,000 barrels of liquids per day from the Benguela Belize Lobito Tomboco development and the Kuito, Tombua and Landana fields. Development and production rights for the various fields in Block 14 expire between 2027 and 2029.

Development drilling continued at the Tombua and Landana fields during 2010. Drilling is planned to continue in 2011 with maximum total daily production of 75,000 barrels of crude oil anticipated in second quarter 2011.

In the Lucapa Field, development alternatives continued to be evaluated during 2010, and a successful exploration well was completed in the fourth quarter. The project is expected to enter FEED in third quarter 2011. A new development area in the Malange Field was awarded in 2010, following a successful 2009 appraisal well. As of the end of 2010, development of the Negage Field remained suspended until cooperative arrangements between Angola and Democratic Republic of the Congo could be finalized. At the end of 2010, proved reserves had not been recognized for these projects.

In the 20 percent-owned Block 2 and the 16.3 percent-owned FST areas, combined production during 2010 averaged 2,000 barrels of net liquids per day.

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 in Soyo, Angola. The plant is designed to process more than 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 2010 with plant start-up scheduled for 2012. The estimated total cost of the LNG plant is $9.0 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. This project is expected to enter construction in the second-half 2011 and be completed by 2013. Proved reserves have been recognized for the producing operations associated with these projects.

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. The Lianzi development project continued FEED through 2010. A final investment decision is expected in fourth quarter 2011. No proved reserves have been recognized for the project.

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. Maximum total production of 93,000 barrels of crude oil per day was reached in fourth quarter 2010 at Moho-Bilondo. Chevron s development and production rights for Moho-Bilondo expire in 2030. The development and production rights for Nsoko, Kitina and Nkossa expire in 2018, 2019 and 2027, respectively. Net production from the Republic of the Congo fields averaged 25,000 barrels of oil-equivalent per day in 2010.

During 2010, two successful exploration wells were drilled in the Moho-Bilondo permit area. Development alternatives are under evaluation.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2010 averaged 2,000 barrels of oil-equivalent.

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Chad/Cameroon: Chevron participates in a project to develop crude oil fields in southern Chad and transport the produced volumes by pipeline to the coast of Cameroon for export. Chevron has a 25 percent nonoperated working interest in the producing operations and an approximate 21 percent interest in two affiliates that own the crude oil export pipeline. Average daily net production from the Chad fields in 2010 was 28,000 barrels of oil-equivalent. The Chad producing operations are conducted under a concession that expires in 2030.

Nigeria: Chevron holds a 40 percent interest in 13 concessions predominantly in the onshore and near-offshore 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 10 deepwater offshore blocks. In 2010, the company s net oil-equivalent production in Nigeria averaged 253,000 barrels per day, composed of 239,000 barrels of liquids and 86 million cubic feet of natural gas.

During July 2010, an equity redetermination at the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128, reduced the company s ownership by about 1 percent, to 67.3 percent. In May 2010, drilling started on a 10-well Phase 2 development program that is designed to offset field decline. The program is expected to continue through 2014 with the first wells expected to be completed and placed on production in second-half 2011. The leases that contain the Agbami Field expire in 2023 and 2024.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in offshore OML 118 share a common geologic structure and are planned to be jointly developed under a unitization agreement. The agreement will be finalized in advance of a final investment decision. Subsurface and surface facility studies are expected to be completed in second quarter 2011. A decision on project scope is expected by third quarter 2011, prior to entering FEED. At the end of 2010, no proved reserves were recognized for this project.

Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery in OML 140. Development activities continued in 2010, with FEED expected to start after commercial terms are resolved and further exploration drilling is completed. At the end of 2010, the company had not recognized proved reserves for this project.

The company holds a 30 percent nonoperated working interest in the deepwater Usan project in OML 138. The development plans involve subsea wells producing to a floating production, storage and offloading (FPSO) vessel. During 2010, development drilling and construction of the FPSO vessel continued. The FPSO vessel is expected to depart the fabrication facility in second quarter 2011. Production start-up is scheduled for 2012, with maximum total production of 180,000 barrels of crude oil per day expected within one year of start-up. Total costs for the project are estimated at $8.4 billion. Usan has an estimated production life of 20 years. Proved reserves have been recognized for this project.

Additional exploration drilling is planned for third quarter 2011 in Oil Prospecting License (OPL) 214 and OPL 223. The company has 20 percent and 27 percent nonoperated working interests in the licenses, respectively. At the end of

2010, proved reserves had not been recognized for these exploration activities.

In the Niger Delta, construction on the Phase 3A expansion of the Escravos Gas Plant (EGP) was completed in 2009, and first gas was delivered to the new facilities in June 2010. As a result of the expansion, the plant s total daily processing capacity increased from 285 million to 680 million cubic feet of natural gas, and daily LPG and condensate export capacity increased from 15,000 to 58,000 barrels. By year-end 2010, plant input had ramped up to 230 million cubic feet of natural gas per day, resulting in daily natural gas sales into the domestic market of 180 million cubic feet and daily export sales of 8,000 barrels of LPG and condensate. The anticipated life of EGP Phase 3A is 25 years. Phase 3B of the EGP project 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 engineering, procurement, construction and installation contract for the gas gathering and compression platform is expected to be signed in second quarter 2011. The Phase 3B project is expected to be completed in 2013. Proved reserves associated with this project have been recognized.

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The 40 percent-owned and operated Gas Supply Expansion project includes facilities to develop the Sonam natural gas field in the Escravos area and to add a third gas processing train at EGP. The project is designed to deliver 215 million cubic feet of natural gas per day to the domestic market and produce 43,000 barrels of liquids per day. A final investment decision is expected in third quarter 2011. At the end of 2010, proved reserves associated with the project had not been recognized.

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. Two on-site construction contracts were awarded in third quarter 2010 and start-up is scheduled for 2012.

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 2010, work on the project was approximately 70 percent complete and start-up is planned for 2013. The estimated cost of the plant is $8.4 billion.

Chevron holds a 19.5 percent interest in the OKLNG Free Zone Enterprise (OKLNG) affiliate, which will operate the Olokola LNG project. OKLNG plans to build a multi-train natural gas liquefaction facility and marine terminal located northwest of Escravos. As of early 2011, timing of the final investment decision remains uncertain. At the end of 2010, proved reserves associated with this project had not been recognized.

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. Compression facilities designed to increase capacity to 170 million cubic feet per day were commissioned in February 2011.

Liberia: In 2010, Chevron acquired a 70 percent interest and operatorship in three deepwater blocks off the coast of Liberia. Three-D seismic data was purchased in September, and an exploration well is planned for fourth quarter 2011.

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 2010, net oil-equivalent production averaged 1,069,000 barrels per day.

Azerbaijan: Chevron holds a 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. In 2010, the company increased its working interest in AIOC from 10.3 percent to 11.3 percent. The company s daily net production from AIOC averaged 30,000 barrels of oil-equivalent in 2010. AIOC operations are conducted under a production-sharing contract (PSC) that expires in 2024.

The final investment decision on the next development phase of the ACG project was made in March 2010, and proved reserves were recognized. The project will further develop the deepwater Gunashli Field. Production is expected to begin in 2013. The total estimated cost of the project is $6 billion with maximum total daily production of 185,000 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 in 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 the marine terminal at Supsa, Georgia.

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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 2010 from these fields averaged 308,000 barrels per day, composed of 252,000 barrels of crude oil and natural gas liquids and 338 million cubic feet of natural gas. During 2010, 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 shipped via other export routes, which included shipment by tanker to Baku for transport by the BTC pipeline to Ceyhan or by rail to Black Sea ports.

Also during 2010, 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 technology developed for the Sour Gas Injection/Second Generation Plant project completed in 2008. Approval of FEED is anticipated in the second-half 2011. As of year-end 2010, no proved reserves have been recognized for this expansion project.

Chevron holds a 20 percent nonoperated working interest in the Karachaganak project, which is being developed in phases. During 2010, Karachaganak net oil-equivalent production averaged 64,000 barrels per day, composed of 39,000 barrels of liquids and 149 million cubic feet of natural gas. In 2010, access to the CPC and Atyrau-Samara (Russia) pipelines enabled approximately 175,000 barrels per day (31,000 net barrels) of Karachaganak liquids to be sold at world-market prices. The remaining liquids were sold into Russian markets. During 2010, work continued on a fourth train that is designed to increase total liquids stabilization capacity by 56,000 barrels per day. The fourth train is expected to start up in second quarter 2011.

During 2010, Chevron and its partners continued to evaluate alternatives for a Phase III development of Karachaganak. Timing for the Phase III project remains uncertain and depends on finalizing a project design. Proved reserves have not been recognized for a Phase III project. Karachaganak operations are conducted under a PSC that expires in 2038.

Kazakhstan/Russia: Chevron has a 15 percent interest in the CPC affiliate. During 2010, CPC transported an average of approximately 743,000 barrels of crude oil per day, including 607,000 barrels per day from Kazakhstan and 136,000 barrels per day from Russia. In December 2010, partners made a final investment decision to increase the 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 full capacity in 2016.

Russia: In June 2010, Chevron signed a Heads of Agreement with Rosneft covering the exploration, development and production of hydrocarbons from the Shatsky Ridge Block in the Black Sea. Technical and commercial evaluation of the opportunity is ongoing in 2011. No proved reserves have been recognized for these activities.

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

Chevron relinquished its 25 percent nonoperated working interest in the Silopi licenses in southeast Turkey, following the evaluation of an unsuccessful exploration well, which was completed in the Lale prospect during first quarter 2010.

Bangladesh: Chevron holds interests in three operated PSCs covering Blocks 7, 12, 13 and 14. The company has a 43 percent interest in Block 7 and a 98 percent interest in Blocks 12, 13 and 14. Net oil-equivalent production from these operations in 2010 averaged 69,000 barrels per day, composed of 404 million cubic feet of natural gas and

2,000 barrels of liquids. In 2010, preliminary construction and development activities were completed at the Muchai compression project, which is expected to support additional production starting in 2012 from the Bibiyana, Jalalabad and Moulavi Bazar natural gas fields. Proved reserves have been recognized for this project. Also in 2010, the company completed seismic data evaluation and prepared to drill an exploration well in Block 7 that is expected to be completed by mid-2011.

Cambodia: Chevron owns a 30 percent interest and operates the 1.2 million-acre Block A, located offshore in the Gulf of Thailand. The company completed three successful exploration wells during 2010. A 30-year production permit under the PSC is expected to be approved by the government in the first-half 2011. A final investment decision for construction of a wellhead platform and a floating storage and offloading vessel is expected in 2011. At year-end 2010, 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 offshore in the Andaman Sea. The company also has a 28.3 percent interest in a pipeline company that transports the natural gas from Yadana to the Myanmar-Thailand border for delivery to power plants in Thailand. Most of the natural gas is purchased by Thailand s PTT Public Company Limited. The company s average net natural gas production in 2010 was 81 million cubic feet per day. In July 2010, a compression project entered service to support additional natural gas demand.

Thailand: Chevron has operated and nonoperated working interests in multiple offshore blocks. The company s net oil-equivalent production in 2010 averaged 216,000 barrels per day, composed of 70,000 barrels of crude oil and condensate and 875 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 2022 and 2035. Chevron has a 16 percent nonoperated working interest in the Arthit Field located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040.

During 2010, construction at the 69.9 percent-owned and operated Platong Gas II project continued. The project is designed to add 440 million cubic feet per day of production capacity and start-up is expected in fourth quarter 2011. Proved reserves have been recognized for this project.

During 2010, the company drilled seven exploration wells in the Pattani Basin. Four of the wells were successful and were under evaluation to validate the development strategy. Three unsuccessful explorations wells were drilled in Block G4/50. In fourth quarter, the company withdrew from this block. At the end of 2010, proved reserves had not been recognized for these activities. For 2011, eleven operated exploratory wells are planned. 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. The company also has a 20 percent ownership interest in an operated PSC in Block 122 offshore eastern Vietnam.

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, field pipelines and a central processing platform. The project entered FEED in 2010, and a final investment decision is expected in fourth quarter 2011. Maximum total production is planned to be about 500 million cubic feet of natural gas per day. At the end of 2010, proved reserves had not been recognized for this project.

In conjunction with the Block B Gas Development, a partner-operated pipeline will be required to support the offshore development. Chevron has a 28.7 percent interest in the pipeline, which is planned to transport natural gas to customers in southern Vietnam. The project entered FEED in 2009, and the engineering and design work is being performed by the pipeline operator.

During the year, seismic processing and prospect mapping were completed for Block 122. Proved reserves had not been recognized as of the end of 2010. Future activity in Block 122 may be affected by an ongoing territorial dispute between Vietnam and China.

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China: Chevron has operated and nonoperated working interests in several areas in China. The company s net oil-equivalent production in 2010 averaged 20,000 barrels per day, composed of 18,000 barrels of crude oil and condensate and 13 million cubic feet of natural gas.

The company operates and holds a 49 percent interest in the Chuandongbei area in the onshore Sichuan Basin, where the company entered into a PSC to develop natural gas resources in 2008. The project includes two sour-gas purification plants with an aggregate design capacity of 740 million cubic feet per day. During 2010, the company continued construction on the first natural gas purification plant and initiated other development activities. First production is expected in 2012, 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. Drilling of one exploration well is also planned for third quarter 2011 in the Chuandongbei area.

In September 2010, the company acquired new operating interests in three deepwater exploration blocks in the South China Sea s Pearl River Mouth Basin. The company has a 100 percent working interest in Blocks 53/30 and 64/18, and a 59.2 percent working interest in Block 42/05 under three separate PSCs for the exploration period. The three deepwater blocks cover approximately 5.2 million acres. One exploration well is planned for 2011 following the completion of an environmental impact study and a 3-D seismic acquisition program.

Also in the Pearl River Mouth Basin, the company has nonoperated working interests of 32.7 percent in Blocks 16/08 and 16/19. Following storm damage in 2009, production was partially restored from Block 16/08 and Block 16/19 in March 2010 and is expected to be fully restored in 2011. Also in Block 16/19, first production from the joint development of the HZ25-3 and HZ25-1 crude oil fields was achieved in March 2010.

In the Bohai Bay, the company holds nonoperated interests of 24.5 percent in the QHD-32-6 Field and 16.2 percent in Block 11/19, both of which are in production. In 2010, production was partially restored from Block 11/19 after a shut-in caused by a storm in 2009. Production is expected to be fully restored in 2013.

Indonesia: Chevron holds interests in operated and nonoperated joint ventures in Indonesia. The company has 100 percent-owned and operated interests in the Rokan and Siak PSCs onshore

Sumatra. The company s interest in the Mountain Front Kuantan PSC was transferred to a local operator in second quarter 2010. Chevron also operates four PSCs in the Kutei Basin, located offshore East Kalimantan. These interests range from 80 percent to 92.5 percent. Chevron also has a 25 percent nonoperated working interest in a joint venture in Block B in the South Natuna Sea. The company relinquished its 40 percent interest in the NE Madura III Block in the East Java Sea Basin in fourth quarter 2010 following an unsuccessful obligation well in 2009. Chevron also relinquished its interest in the 100 percent-owned and operated East Ambalat PSC in December 2010. The relinquishments of NE Madura III and East Ambalat are both pending approval by the government of Indonesia.

The company s net oil-equivalent production in 2010 from all of its interests in Indonesia averaged 226,000 barrels per day. The daily oil-equivalent rate comprised 187,000 barrels of liquids and 236 million cubic feet of natural gas. The largest producing field is Duri, located in the Rokan PSC. Duri has been under steamflood operation since 1985 and is one of the world s largest steamflood developments. The North Duri Development is divided into multiple expansion areas.

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The expansion in Area 12 was completed in 2010 with the additional drilling of 72 production, 24 steam injection, and 10 observation wells. During the year, ramp-up of steam injection continued with the project reaching a maximum total daily production of 45,000 barrels in September 2010. A final investment decision regarding North Duri Area 13 was reached May 2010, and is awaiting final development plan and bid award approvals from the government of Indonesia. The Rokan PSC expires in 2021.

In 2010, Chevron advanced its development plans for the Gendalo-Gehem deepwater natural gas project located in the Kutei Basin, awarding major FEED contracts for the floating production units, subsea and pipeline components, and onshore receiving facility. Maximum daily total production from the project is expected to be 1.1 billion cubic feet of natural gas and 31,000 barrels of condensate. Completion of FEED is dependent upon government approvals and achieving project milestones. The Bangka deepwater natural gas project progressed during the year, and entered FEED in fourth quarter 2010. During 2010, the company reached an agreement to farm-out a portion of its working interest in the PSCs of the two projects. Government approval of the farm-out is expected in the second-half 2011. In addition, in 2011 the company expects to farm-in an Indonesian company to the PSCs for the two projects. Following government approval of the agreements, the company s production interest in the Gendalo-Gehem and Bangka projects will be 55.1 percent and 54 percent, respectively. Proved reserves have not been recognized for these projects.

Also in the Kutei Basin, the company reached a final investment decision in August 2010 for an oil development project in the West Seno Field and recognized proved reserves related to the project.

A drilling campaign continued through 2010 in South Natuna Sea Block B to provide additional supply for long-term natural gas sales contracts, with additional development drilling planned for 2011. The North Belut development project achieved maximum total daily production of 240 million cubic feet of natural gas and 33,000 barrels of liquids in February 2010. Development of the South Belut project continued during the year. The Bawal project reached final investment decision in October 2010 and is expected to begin production in 2012.

Exploration activities continued in the Central Sumatra Basin during 2010. Two wells drilled in the Rokan Block were successful and placed on production. Additional appraisal drilling near the Duri Field identified further expansion opportunities that will be further assessed with 3-D seismic in 2011. Chevron s operated working interests in two exploration blocks in western Papua, West Papua I and West Papua III, were reduced to 51 percent in second quarter 2010. Geological studies of the two blocks continued in 2010, and 2-D seismic acquisition is expected to start in the first-half 2011.

In West Java, Chevron operates the wholly owned Salak geothermal field with a total power-generation capacity of 377 megawatts. Also in West Java, Chevron 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 North Duri, Sumatra. In December 2010, the company was awarded a license and operatorship to explore and develop a geothermal prospect in the Suoh-Sekincau prospect area at Lampung in southern Sumatra.

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 2010, the company s average net oil-equivalent production was 98,000 barrels per day, composed of 94,000 barrels of crude oil and 23 million cubic feet of natural gas. During 2010, the company continued to evaluate data from a steam injection pilot project that was initiated in 2009. The pilot is an application of steam injection into a carbonate reservoir and, if successful, could significantly increase heavy oil recovery. No proved reserves have been recognized for this project.

Also in 2010, assessment of alternatives continued on the Central Gas Utilization Project to increase natural gas utilization and eliminate routine flaring. A final investment decision is expected in 2012. No proved reserves have 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 2010 averaged 25,000 barrels per day, composed of 124 million cubic feet of natural gas and 4,000 barrels of condensate. Chevron also develops and produces geothermal resources under an agreement with the Philippine government. Chevron expects to sign a new 25-year contract with the government by the end of 2011 to operate the steam fields, which supply geothermal resources to 637 megawatt power generation facilities.

In November 2010, Chevron signed a farm-in agreement and a Joint Operating Agreement with two Philippine corporations to explore, develop and operate the Kalinga geothermal prospect in northern Luzon, Philippines. The company has a 90 percent-owned and operated interest in the project.

e) Australia

In Australia, the company s exploration and production efforts are concentrated off the northwest coast. During 2010, the average net oil-equivalent production from Australia was 111,000 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 2010 averaged 25,000 barrels of crude oil and condensate, 456 million cubic feet of natural gas, and 5,000 barrels of LPG. Approximately 70 percent of the natural gas was sold in the form of LNG to major utilities in Japan, South Korea and China, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market.

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. Modifications for process tie-ins and a barge link from North Rankin A progressed during 2010. Upon completion, North Rankin A and B are designed to be operated as a single integrated facility. The project is scheduled to start production in 2013. Proved reserves have been recognized for the project.

Work also progressed on the NWS Oil Redevelopment Project, which is designed to replace the existing FPSO vessel and a portion of existing subsea infrastructure that services production from the Cossack, Hermes, Lambert and Wanaea offshore fields. Work commenced in January 2011 on the subsea infrastructure refurbishment, and construction of the new FPSO vessel is expected to be completed in second quarter 2011. The project is expected to start up in third quarter 2011 and extend production past 2020.

The NWS Venture continues to progress additional gas supply opportunities through development of several small fields on the western flank of the Goodwyn reservoirs. The project is expected to enter FEED in the first-half 2011. The concession for the NWS Venture expires in 2034.

On Barrow and Thevenard islands off the northwest coast of Australia, Chevron operates crude oil producing facilities that had combined net production of 4,000 barrels per day in 2010. Chevron s interests in these operations are 57.1 percent for Barrow and 51.4 percent for Thevenard.

Also off the northwest coast of Australia, Chevron holds significant equity interests in the large natural gas resource of the Greater Gorgon Area. The company holds a 47.3 percent ownership interest across most of the area and is the operator of the Gorgon Project, which combines the development of the offshore Gorgon and nearby Io/Jansz natural gas fields as one large-scale project. Total estimated project costs for the first phase of development are $37 billion. The project s scope also includes a three-train, 15 million-metric-ton-per-year LNG facility, a carbon sequestration project and a domestic natural gas plant.

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Chevron has signed five binding LNG Sales and Purchase Agreements (SPAs) with Asian customers for delivery of about 4.7 million metric tons of LNG per year. Negotiations continue to finalize the two remaining nonbinding Heads of Agreement (HOAs) to binding SPAs, which would bring LNG delivery commitments to a combined total of about 90 percent of Chevron s share of LNG from the project. Construction on Barrow Island and other activities for the project progressed during 2010 with the awarding of approximately $25 billion of contracts for materials and services, clearing of the plant site, completion of the first stage of the construction village, commencement of module fabrication, and progression of studies on the possible expansion of the project. 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 2014. The project s estimated economic life exceeds 40 years from the time of start-up.

FEED activities for the company s majority-owned and operated Wheatstone Project continued in 2010. Chevron holds an 80 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 facilities from two Chevron-operated licenses comprising the majority of the Wheatstone Field and the nearby Iago Field.

Through the end of 2010, Chevron has signed nonbinding HOAs with three Asian customers for the delivery of about 80 percent of Chevron s net LNG offtake from the Wheatstone Project. Under these HOAs, the customers also agreed to acquire a combined 21.8 percent nonoperated working interest in the Wheatstone field licenses and a 17.5 percent interest in the foundation natural gas processing facilities at the time of the final investment decision. Negotiations continue to move the three nonbinding HOAs to binding SPAs with these customers. Agreements were also signed in 2009 and amended in 2010 with two companies to participate in the Wheatstone Project as combined 20 percent LNG facility owners and suppliers of natural gas for the project s first two LNG trains. During 2010, a Native Title Heads of Agreement was reached with the local indigenous people for the land required at Ashburton North and submissions were made for various additional environmental approvals. The final investment decision for the project is expected in second-half 2011. At the end of 2010, the company had not recognized proved reserves for this project.

In the Browse Basin, the Browse LNG development participants commenced design evaluation for the Brecknock, Calliance and Torosa fields in early 2010. At the end of 2010, proved reserves had not been recognized.

During 2010, Chevron announced natural gas discoveries at the 50 percent-owned Brederode prospect in Block WA-364-P, the 50 percent-owned Yellowglen prospect in Block WA-268-P, the 50 percent-owned Sappho prospect in Block WA-392-P, and the 67 percent-owned Clio and Acme prospects in Block WA-205-P. In February 2011, the company announced a natural gas discovery in the 50 percent-owned Orthrus prospect in Block WA-24-R. All prospects are Chevron operated. The Clio and Acme prospects are expected to help support potential expansion opportunities at the Wheatstone LNG facilities while the Yellowglen, Sappho and Orthrus prospects are expected to help underpin further expansion opportunities on the Gorgon Project. Proved reserves had not been recognized for any of these exploration discoveries.

f) Europe

In Europe, the company is engaged in exploration and production activities in Denmark, the Netherlands, Norway, Poland, Romania and the United Kingdom. Net oil-equivalent production in Europe averaged 159,000 barrels per day during 2010.

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 of 15 fields in the Danish North Sea. Net oil-equivalent production in 2010 from DUC averaged 51,000 barrels per day, composed of 32,000 barrels of crude oil and 116 million cubic feet of natural gas. During 2010, four development wells were drilled and completed in the Halfdan, Tyra and Valdemar fields. The installation of new facilities for the Halfdan Phase IV project was completed in 2010, with hook-up and tie-in planned for second quarter 2011.

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 2010, the company s net oil-equivalent production from the producing blocks was 8,000 barrels per day, composed of 2,000 barrels of crude oil and 35 million cubic feet of natural gas. Five blocks comprise the A/B Gas Project, where development continued in 2010 and into 2011. In September 2010, the company acquired a 60 percent interest in the P/1 and P/2 blocks, which contain several natural gas discoveries.

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 2010. Chevron is the operator and has a 40 percent working interest in exploration license PL 527 in the deepwater portion of the Norwegian Sea. In 2010, Chevron focused on processing data from a 2-D seismic survey. In February 2011, the company relinquished its 40 percent nonoperated working interest in the PL 397 license in the Barents Sea.

Poland: Acquisition work commenced in October 2010 on a 2-D seismic survey across Chevron s four 100 percent-owned and operated shale gas licenses in southeast Poland (the Zwierzyniec, Kransnik, Frampol and Grabowiec concessions). These licenses cover a combined total of 1.1 million acres. The data will be used to plan a multi-well drilling program expected to start toward the end of 2011.

Romania: In July 2010, the company was the successful bidder for three shale gas exploration blocks. Blocks 17, 18 and 19 in southeast Romania comprise approximately 670,000 acres. Negotiation of the license agreements for these blocks continued into 2011. In addition, the company acquired a 100 percent interest in the EV-2 Barlad shale gas concession in February 2011. This license, located in northeast Romania, covers 1.5 million acres. A 2-D seismic program is planned to begin in fourth quarter 2011 on the EV-2 Barlad concession.

United Kingdom: The company s average net oil-equivalent production in 2010 from 10 offshore fields was 97,000 barrels per day, composed of 64,000 barrels of crude oil and natural gas liquids and 194 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 70 percent-owned and operated Alder discovery entered FEED in 2010, following selection of the development concept. The final investment decision is planned for late 2011. Evaluation of development alternatives continued during 2010 for the Clair Ridge Project, located west of the Shetland Islands, in which the company has a 19.4 percent nonoperated working interest. Evaluation resulted in the selection of a preferred alternative consisting of a bridge-linked, twin-jacket structure. The final investment decision is expected mid-2011. In the 40 percent-owned and operated Rosebank area northwest of the Shetland Islands, seismic, geophysical, geotechnical and environmental surveys were conducted during 2010, and feasibility engineering activities are scheduled to continue through 2011. At the end of 2010, proved reserves had not been recognized for any of these development projects.

Also west of the Shetland Islands, a three-well exploration and appraisal drilling program began in September 2010 and is expected to be completed in fourth quarter 2011. This program comprises exploration wells on the Lagavulin prospect in the 60 percent-owned and operated license block P1196 and on the Aberlour prospect in the 40 percent-owned and operated license block P1194, followed by appraisal drilling and well testing of the Cambo discovery in the 32.5 percent nonoperated license blocks P1028 and P1189. As of the end of 2010, proved reserves had not been recognized for any of these prospects.

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 2010, U.S. and international sales of natural gas were 5.9 billion and 4.5 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 105 thousand barrels per day, respectively, in 2010. Substantially all of the international sales of natural gas liquids are from company operations in Africa, Australia, Indonesia and the United Kingdom.

Refer to Selected Operating Data, on page FS-11 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 8 for information related to the company s delivery commitments for the sale of crude oil and natural gas.

Downstream

Refining Operations

At the end of 2010, the company had a refining network capable of processing more than 2 million barrels of crude oil per day. Operable capacity at December 31, 2010, and daily refinery inputs for 2008 through 2010 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)

		December 31, 2010				
			Operable		**Refinery Inputs**	
Locations		**Number**	**Capacity**	**2010**	**2009**	**2008**
Pascagoula	Mississippi	**1**	**330**	**325**	345	299
El Segundo	California	**1**	**269**	**250**	247	263
Richmond	California	**1**	**243**	**228**	218	237
Kapolei	Hawaii	**1**	**54**	**46**	49	46
Salt Lake City	Utah	**1**	**45**	**41**	40	38
Perth Amboy[1]	New Jersey	**1**	**80**			8
Total Consolidated Companies	**United States**	**6**	**1,021**	**890**	899	891
Pembroke	United Kingdom	**1**	**210**	**211**	205	203
Cape Town[2]	South Africa	**1**	**110**	**70**	72	75
Burnaby, B.C.	Canada	**1**	**55**	**40**	49	36
Total Consolidated Companies	**International**	**3**	**375**	**321**	326	314
Affiliates[3]	Various Locations	**8**	**764**	**683**	653	653
Total Including Affiliates	**International**	**11**	**1,139**	**1,004**	979	967
Total Including Affiliates	**Worldwide**	**17**	**2,160**	**1,894**	1,878	1,858

[1] Perth Amboy has been idled since early 2008 and is operated as a terminal.

[2] 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 2011.

[3] Includes 3,000 and 6,000 barrels per day of refinery inputs in 2009 and 2008, respectively, for interests in refineries that were sold during those periods.

Average crude oil distillation capacity utilization during 2010 was 92 percent, compared with 91 percent in 2009. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 95 percent in 2010, compared with 96 percent in 2009, and cracking and coking capacity utilization averaged 90 percent and 85 percent in 2010 and 2009, respectively. Cracking and coking units are the primary facilities used in fuel refineries to convert feedstocks into gasoline and other light products. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 84 percent and 85 percent of Chevron s U.S. refinery inputs in 2010 and 2009, respectively.

At the Pascagoula Refinery, the company commissioned a continuous catalytic reformer that is expected to improve equipment reliability and utilization and to allow the refinery to optimize production of high-value products. Also in Pascagoula, a final investment decision was reached in first quarter 2011 to construct 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.

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At the refinery in El Segundo, construction began in late 2010 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 2012. At the Richmond Refinery, the company continued to evaluate its options with respect to permitting of the Renewal Project. 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-59.

Outside the United States, GS Caltex, the company s 50 percent-owned affiliate, commissioned and reached full capacity on a new 60,000-barrel-per-day heavy-oil hydrocracker at the Yeosu Refinery in South Korea during 2010. Also at the Yeosu Refinery, GS Caltex announced plans to construct a 53,000-barrel-per-day gas oil fluid catalytic cracking unit. The unit is scheduled for start-up in 2013. Both units are designed to increase high-value product yield and lower feedstock costs. Construction began in 2010 on modifications to the 64 percent-owned Star Petroleum Refinery in Thailand to meet regional specifications for cleaner motor gasoline and diesel fuels. Project completion is scheduled for 2012. Also in 2010, the company solicited bids for the sale of certain operations in the United Kingdom and Ireland, including the Pembroke Refinery.

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, 2010.

Refined Products Sales Volumes
(Thousands of Barrels per Day)

	2010	**2009**	**2008**
United States			
Gasoline	**700**	720	692
Jet Fuel	**223**	254	274
Gas Oil and Kerosene	**232**	226	229
Residual Fuel Oil	**99**	110	127
Other Petroleum Products[1]	**95**	93	91
Total United States	**1,349**	1,403	1,413
International[2]			
Gasoline	**521**	555	589
Jet Fuel	**271**	264	278
Gas Oil and Kerosene	**583**	647	710
Residual Fuel Oil	**197**	209	257
Other Petroleum Products[1]	**192**	176	182
Total International	**1,764**	1,851	2,016
Total Worldwide[2]	**3,113**	3,254	3,429

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

[2] Includes share of equity affiliates sales:	562	516	512

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2010, the company supplied directly or through retailers and marketers approximately 8,250 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 500 of these outlets are company-owned or -leased stations. In 2010, the company discontinued sales of Chevron- and Texaco-branded motor fuels in the District of Columbia, Delaware, Indiana, Kentucky, North Carolina, New Jersey, Maryland, Ohio, Pennsylvania, South Carolina, Virginia, West Virginia and parts of Tennessee, where the company sold to retail customers through approximately 1,100 stations and to commercial and industrial customers through supply arrangements. Sales in these markets represented approximately 8 percent of the company s total U.S. retail fuels sales volumes in 2009. In addition, the company has completed six of 13 planned U.S. terminal divestitures.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 11,300 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. The company markets in the United Kingdom, Ireland, 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 progressed its ongoing effort to concentrate downstream resources and capital on strategic assets. In December 2010 and February 2011, the company completed the sale of fuels-marketing businesses in Malawi, Mauritius, Réunion, Tanzania and Zambia. The company expects to complete the sale of its fuels-marketing businesses in Mozambique and Zimbabwe later in 2011, following receipt of required local regulatory and government approvals. In November 2010, the company signed an agreement for the sale of its fuels-marketing and aviation fuels businesses in Antigua, Barbados, Belize, Costa Rica, Dominica, French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Nicaragua, St. Kitts, St. Lucia, St. Vincent, and Trinidad and Tobago and expects to complete all transactions by third quarter 2011, following receipt of required local regulatory and government approvals. In February 2011, the company announced an agreement to sell its fuels, finished lubricants and aviation fuels businesses in Spain. In 2010, the company also solicited bids for its fuels-marketing and aviation fuels businesses in the United Kingdom and Ireland. In addition, the company converted more than 150 company-operated service stations into retailer-owned sites in various countries outside the United States.

Chevron markets commercial aviation fuel at approximately 200 airports, worldwide. The company also markets an extensive line of lubricant and coolant products under brand names including 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 2010, CPChem owned or had joint-venture interests in 36 manufacturing facilities and four research and technical centers around the world.

During 2010, CPChem commenced operations at its 49 percent-owned Q-Chem II project in both Mesaieed and Ras Laffan, Qatar. The project includes a 350,000-metric-ton-per-year high-density polyethylene plant and a 345,000-metric-ton-per-year normal alpha olefins plant in Mesaieed, each utilizing CPChem s proprietary technology. Also included in the project is a separate joint venture for a 1.3 million-metric-ton-per-year ethylene cracker in Ras Laffan, in which Q-Chem II owns 54 percent of the capacity rights, which will provide ethylene feedstock to the high-density polyethylene and normal alpha olefins plants.

CPChem s 35 percent-owned Saudi Polymers Company continued construction on a petrochemical project in Al Jubail, Saudi Arabia. The joint-venture project includes olefins, polyethylene, polypropylene, 1-hexene and polystyrene units. Project start-up is expected in late 2011.

In the United States, CPChem announced in fourth quarter 2010 the development of a 200,000-ton-per-year 1-hexene plant at the company s Cedar Bayou complex in Baytown, Texas, with start-up 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.

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. During 2010, the company achieved full capacity at the detergent expansion facility in Singapore. This additional capacity enhances the company s ability to produce detergent components for applications in marine and automotive engines.

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, 2010

	Net Mileage[1,2]
United States:	
Crude Oil	2,417
Natural Gas	2,400
Petroleum Products[3]	5,456
Total United States	10,273
International:	
Crude Oil[4]	700
Natural Gas[5]	650
Petroleum Products[3]	424
Total International	1,774
Worldwide	12,047

[1] Partially owned pipelines are included at the company s equity percentage of total pipeline mileage.
[2] Excludes gathering pipelines relating to the crude oil and natural gas production function.
[3] Includes the company s share of chemical pipelines managed by the 50 percent-owned CPChem.
[4] Includes the company s share of Chad/Cameroon pipeline, Baku-Tbilisi-Ceyhan Pipeline, Western Route Export Pipeline and Caspian Pipeline.
[5] Includes the company s share of West Africa Gas Pipeline.

During 2010, the company completed a project to expand capacity by approximately 2 billion cubic feet at the Keystone natural gas storage facility near Midland, Texas, bringing total capacity to nearly 7 billion cubic feet.

Work continued in 2010 to bring the Cal-Ky Pipeline, which was decommissioned in 2002, back into 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 pipeline is expected to return to service in 2012. 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 Louisiana.

In 2010, the company sold its 23.4 percent ownership interest in the Colonial Pipeline Company, which transports products from supply centers on the U.S. Gulf Coast to customers located along the Eastern seaboard.

Refer to pages 16, 17 and 18 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 2010. At any given time during 2010, the company had 41 deep-sea vessels chartered on a voyage basis, or for a period of less than one year. Additionally, the table on the following page summarizes the capacity of the company s controlled fleet.

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Controlled Tankers at December 31, 2010[1]

	U.S. Flag		Foreign Flag	
	Number	Cargo Capacity (Millions of Barrels)	Number	Cargo Capacity (Millions of Barrels)
Owned	1	0.2	1	1.1
Bareboat-Chartered	4	1.4	17	25.0
Time-Chartered[2]			14	10.6
Total	5	1.6	32	36.7

[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.

Federal law requires that cargo transported between U.S. ports be carried in ships built and registered in the United States, owned and operated by U.S. entities, and manned by U.S. crews. 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. As part of its fleet modernization program, the company replaced two U.S.-flagged product tankers in 2010. The company plans to retire one additional U.S.-flagged product tanker in 2011. The new tankers are expected to bring improved efficiencies to Chevron s U.S.-flagged fleet.

The foreign-flagged vessels are engaged primarily in transporting crude oil from the Middle East, Southeast Asia, the Black Sea, 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 owns a one-sixth interest in each of seven liquefied natural gas tankers transporting cargoes for the North West Shelf Venture in Australia.

Chevron s fleet of owned and chartered tankers is completely double-hulled. The company is a member of many oil-spill-response cooperatives in areas in which it operates around the world.

Other Businesses

Mining

Chevron s U.S.-based mining company produces and markets coal and molybdenum. Sales occur in both U.S. and international markets.

The company owns and is the operator of an underground coal mine, North River, in Alabama, and surface coal mines in Kemmerer, Wyoming, and McKinley, New Mexico. The company also owns a 50 percent interest in Youngs Creek Mining Company, LLC, which was formed to develop a coal mine in northern Wyoming.

As of early 2011, the sale of the North River Mine and other coal-related assets in Alabama was under negotiation. Additionally, in January 2011, the company announced the intent to divest its remaining coal mining operations. Activities related to full reclamation continued in 2010 at the company s McKinley, New Mexico, mine, which ceased coal production at the end of 2009.

At year-end 2010, Chevron controlled approximately 189 million tons of proven and probable coal reserves in the United States, including reserves of low-sulfur coal. The company is contractually committed to deliver between 7 million and 8 million tons of coal per year through the end of 2013 and believes it will satisfy these contracts from existing coal reserves. Coal sales from wholly owned mines in 2010 were 8 million tons, down about 2 million tons from 2009.

In addition to the coal operations, Chevron owns and operates the Questa molybdenum mine in New Mexico. At year-end 2010, Chevron controlled approximately 53 million pounds of proven molybdenum reserves at Questa. Production and underground development at Questa continued at reduced levels in 2010 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 waste heat recovery to produce electricity and support industrial thermal hosts. The thirteenth 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 21 and 22 and Research and Technology below.

Chevron Energy Solutions (CES)

CES is a wholly owned subsidiary that develops and builds sustainable energy projects to increase energy efficiency and 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 help customers reduce their energy costs and environmental impact. Projects announced in 2010 include the City of Brea Energy Efficiency and Solar Project in California, the Marine Corps Logistics Base Albany Landfill Gas Project in Georgia, and the University of Utah Thermal Storage and New Central Plant Project.

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 2010, CTV continued to explore technologies such as next-generation biofuels and advanced solar. In 2010, the company constructed and commissioned a one megawatt concentrating photovoltaic (CPV) solar facility on the tailing site of Chevron s molybdenum mine in Questa, New Mexico. This beneficial reuse project is one of the largest CPV installations in the world. Also in 2010, the company constructed and commissioned a 0.74 megawatt next generation solar photovoltaic installation on a former refinery site in Bakersfield, California. Seven solar panel technologies are being tested to establish the viability of these solar technologies at other Chevron sites.

Chevron s research and development expenses were $526 million, $603 million and $702 million for the years 2010, 2009 and 2008, 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

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 its operations are, or are expected to become, embedded in the normal costs of conducting business.

In 2010, the company s U.S. capitalized environmental expenditures were $639 million, representing about 12 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 2011, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $800 million. The future annual capital costs are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Environmental-related regulations, including those intended to address concerns about greenhouse gas emissions and global climate change, continue to evolve. For instance, in December 2009, the U.S. Environmental Protection Agency (EPA) issued a final endangerment finding for greenhouse gases, which found that emissions of six greenhouse gases threaten the public health and welfare. Greenhouse gases from new motor vehicles and engines also contribute to such pollution. Subsequently, in 2010, the EPA finalized two regulations under the Clean Air Act that establish greenhouse gas emission standards for new light-duty vehicles and clarify preconstruction permitting requirements for new or modified stationary source facilities with greenhouse gas emissions that exceed 75,000 tons per year of carbon dioxide equivalent. In November 2010, the agency issued updated guidance on determining the best available control technologies (BACT) that would be required to be implemented by certain new and modified stationary source facilities beginning in January 2011, but there remains significant uncertainty regarding the impact of applying BACT requirements on a case by case basis. Finally, in two recent settlement agreements, the EPA agreed to schedules for undertaking additional greenhouse gas rulemakings applicable to utilities and refineries. The agency is beginning to develop these new regulations, which are scheduled to be effective in May 2012 (utilities) and November 2012 (refineries), so it is not possible to predict their impact at this time. The EPA s endangerment finding, motor vehicle greenhouse gas standards, and greenhouse gas permit rule have all been challenged in federal courts and decisions are pending.

The EPA also finalized its revised Renewable Fuel Standard (RFS2) regulations as required by the Energy Independence and Security Act of 2007. The regulations require fuel providers to blend increased volumes of renewable fuels into gasoline and diesel each year and establish specific greenhouse gas reduction and feedstock criteria for subcategories of renewable fuel, including cellulosic fuel, advanced biofuel and biomass-based diesel. The specific impacts of this regulation are determined by many factors, including fluctuating markets for renewable fuels and EPA regulatory decisions on potential waivers of volume requirements.

Additionally, under California s Global Warming Solutions Act, enacted in 2006, the California Air Resources Board (CARB), charged with implementing the law, has adopted a new low-carbon fuel standard intended to reduce the carbon intensity of transportation fuels. The state is behind schedule in completing certain elements of the standard. Consequently, initial carbon intensity reduction requirements are effective as of January 2011, but CARB has delayed other aspects of compliance until it completes further updates to the regulation later in the year. In December 2010, CARB adopted regulations implementing the cap and trade program requirements of the Global Warming Solutions Act. The first compliance period of the cap and trade program begins in 2012 and ends in December 2014. CARB has yet to develop detailed regulations to implement this portion of the Act, including the determination of how emissions allowances will be allocated and traded during this period. The effect of any such regulation on the company s business is uncertain.

Refer to Management s Discussion and Analysis of Financial Condition and Results of Operations on pages FS-17 through FS-20 for additional information on environmental matters and their impact on Chevron and on the company s 2010 environmental expenditures, remediation provisions and year-end environmental reserves. Refer also to Item 1A. Risk Factors on pages 32 through 34 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.

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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 fund capital and exploratory expenditures and to pay dividends. 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 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.

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 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, explosions and system failures, 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 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 the company s 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 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.

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Political instability 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 restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company s continued presence in those countries. Internal unrest, acts of violence or strained relations between a government and the company or other governments may 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, 2010, 25 percent of the company s net proved reserves were located in Kazakhstan. The company also has significant interests in Organization of Petroleum Exporting Countries (OPEC)-member countries including Angola, Nigeria and Venezuela and in the Partitioned Zone between Saudi Arabia and Kuwait. Twenty-three percent of the company s net proved reserves, including affiliates, were located in OPEC countries at December 31, 2010.

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. For instance, the Kyoto Protocol and California s Global Warming Solutions Act, along with other actual or pending federal, state and provincial regulations, envision a reduction of greenhouse gas emissions through market-based regulatory programs, technology-based or performance-based standards or a combination of them. The company is subject to existing greenhouse gas emissions limits in jurisdictions where such regulation is currently effective, including the European Union and New Zealand.

In 2010, the U.S. Environmental Protection Agency (EPA) finalized two regulations under the Clean Air Act that establish greenhouse gas emission standards for new light-duty vehicles and clarify preconstruction permitting requirements for new or modified stationary source facilities with greenhouse gas emissions that exceed 75,000 tons per year of carbon dioxide equivalent. In addition, the EPA recently agreed to develop additional regulations on greenhouse gas emissions from utilities and refineries. The agency is beginning to develop these new regulations, which are scheduled to be effective in May 2012 (utilities) and November 2012 (refineries), so it is not possible to predict their impact at this time.

The U.S. Congress has previously considered and may in the future consider legislation aimed at reducing greenhouse gas emissions. At this time it is not possible to predict any specific Congressional actions in 2011 or beyond, and it is unclear how any such legislation would reconcile with the Clean Air Act or current EPA regulations.

In December 2010, California adopted regulations implementing the cap and trade program requirements of the state s Global Warming Solutions Act, also known as AB32. The first compliance period of the cap and trade program begins in 2012 and ends in December 2014. Chevron may incur costs associated with emissions reduction activities, and the purchase of allowances or credits for its facilities in California. In addition, Chevron s purchased energy costs from utilities may increase starting in January 2012, when electricity generators are required to purchase allowances or credits for electricity sold in California.

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 by jurisdiction depending on the laws enacted in each jurisdiction, the company s activities in it and market conditions. The company s exploration and production of crude oil, natural gas and various minerals such as coal; 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 result in greenhouse gas emissions that could well be regulated. 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.

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-66 through FS-80. Note 13, Properties, Plant and Equipment, to the company s financial statements is on page FS-45.

Item 3. Legal Proceedings

Ecuador

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

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

In 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $18.9 billion, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer s report also asserted that an additional $8.4 billion could be assessed against Chevron for unjust enrichment. In 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case was recused. In 2010, Chevron moved to strike the mining engineer s report and to dismiss the case based on evidence obtained through discovery in the United States indicating that the report was prepared by consultants for the plaintiffs before being presented as the mining engineer s independent and impartial work and showing further evidence of misconduct. In August 2010, the judge issued an order stating that he was not bound by the mining engineer s report and requiring the parties to provide their positions on damages within 45 days. Chevron subsequently petitioned for recusal of the judge, claiming that he had disregarded evidence of fraud and misconduct and that he had failed to rule on a number of motions within the statutory time requirement.

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

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador s obligations under the United States-Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador s obligations under the BIT. On February 9, 2011, the Permanent Court of Arbitration issued an Order for Interim Measures requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. Chevron expects to continue seeking permanent injunctive relief and monetary relief before the Tribunal.

Through a series of recent U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron has obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron is seeking relief that includes an award of damages and a declaration that any judgment against Chevron in the Lago Agrio litigation is the result of fraud and other unlawful conduct and is therefore unenforceable. On February 8, 2011, the Court issued a temporary restraining order prohibiting the Lago Agrio plaintiffs and persons acting in concert with them from taking any action in furtherance of recognition or enforcement of any judgment against Chevron in the Lago Agrio case until March 8, 2011. Chevron s motion for a preliminary injunction is presently before the Court.

On February 14, 2011, the Provincial Court in Lago Agrio rendered an adverse judgment in the case. The Provincial Court rejected Chevron s defenses to the extent the Court addressed them in its opinion. The judgment assesses approximately $8.6 billion in damages and about $0.9 billion for the plaintiffs representatives. It also assesses an additional amount of approximately $8.6 billion in punitive damages unless the company provides a public apology. Chevron continues to believe the Court s judgment is illegitimate and unenforceable in Ecuador, the United States and other countries. The company also believes the judgment is the product of fraud, and contrary to the legitimate scientific evidence. Chevron will appeal this decision in Ecuador. Chevron cannot predict the timing or ultimate outcome of the appeals process in Ecuador. Chevron will continue a vigorous defense of any imposition of liability. Because Chevron has no substantial assets in Ecuador, Chevron would expect enforcement actions as a result of this judgment to be brought in other jurisdictions. Chevron expects to contest any such actions.

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

California Air Resources Board

As reported in the company s annual report on Form 10-K for the year ended December 31, 2009, in November 2008, the California Air Resources Board (CARB) proposed a civil penalty against the company 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 had failed to inject additive detergent into a gasoline line.

As reported in the company s annual report on Form 10-K for the year ended December 31, 2009, in November 2008, CARB proposed a civil penalty against the company s Richmond, California, refinery for a notice of violation relating to gasoline that was not properly certified as to composition. The company corrected the composition certificates for the gasoline 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.

As reported in the company s quarterly report on Form 10-Q for the quarter ended September 30, 2010, on July 14, 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 the company on discovery. The company has determined that resolution of this matter may result in the payment of a civil penalty exceeding $100,000.

Other Government Proceedings

As reported in the company s annual report on Form 10-K for the year ended December 31, 2009, 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 the company undertook to install and operate certain air pollution abatement equipment at its Hawaii Refinery pursuant to Clean Air Act settlement with the United States Environmental Protection Agency and DOH. The company has disputed many of the allegations.

As reported in the company s quarterly report on Form 10-Q for the quarter ended March 31, 2010, in March 2010, the United States Department of Justice (DOJ) indicated that it intends to seek a civil penalty against the company s service station operations in Puerto Rico for alleged violations of the Commonwealth of Puerto Rico s underground storage tank regulations. The alleged violations include failure to test leak detectors, perform release monitoring and maintain compliance records. The DOJ s action may result in payment of a civil penalty exceeding $100,000.

As reported in the company s quarterly report on Form 10-Q for the quarter ended June 30, 2010, Chevron has entered into negotiations with the United States Environmental Protection Agency (EPA) with respect to alleged air pollution violations at the company 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 will result in the payment of a civil penalty exceeding $100,000.

In the fourth quarter 2010, Chevron paid the United States Department of Transportation a $423,000 civil penalty as the result of an 800 barrel crude oil spill that occurred on June 12, 2010. The spill originated from a pipeline that runs from the company s Rangely Colorado Field to its Salt Lake Refinery.

The California Attorney General has alleged violations of the State s underground storage tank regulations at the company s service stations in the State of California. The allegations are part of a state-wide enforcement action which the company determined in the fourth quarter 2010 may result in the payment of a civil penalty exceeding $100,000.

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-24.

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, 2010	**17,025**	**83.82**		
Nov. 1 Nov. 30, 2010	**4,743,062**	**83.25**	**4,595,000**	
Dec. 1 Dec. 31, 2010	**4,178,507**	**87.82**	**4,175,800**	
Total Oct. 1 Dec. 31, 2010	**8,938,594**	**85.45**	**8,770,800**	

(1) Pertains to common shares repurchased during the three-month period ended December 31, 2010, 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, 2010.

(2) In July 2010, the company terminated the $15 billion share repurchase program initiated in September 2007. No share repurchases occurred in 2010 prior to the termination of this program. From the inception of that program, the company acquired 118,996,749 shares at a cost of $10.1 billion. In its place, the Board of Directors approved a new, ongoing share repurchase program with no set term or monetary limits, under which common shares would be acquired by the company at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. As of December 31, 2010, 8,770,800 shares had been acquired under this program for $750 million.

Item 6. Selected Financial Data

The selected financial data for years 2006 through 2010 are presented on page FS-65.

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-15 and in Note 10 to the Consolidated Financial Statements, Financial and Derivative Instruments, beginning on page FS-39.

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.

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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, 2010.

(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, 2010.

The effectiveness of the company s internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page FS-26.

(c) Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2010, 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

The company s coal and other mine safety information is presented in Exhibit 99.2 on page E-28.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 24, 2011

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	54	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	60	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.E. Bethancourt	59	Executive Vice President (since 2003)*	Technology; Mining; Health, Environment and Safety; Project Resources Company; Procurement
J.R. Blackwell	52	Executive Vice President (as of March 1, 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	50	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	53	Executive Vice President (as of March 1, 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	54	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	48	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

* Effective through February 28, 2011.

The information about directors required by Item 401(a) and (e) of Regulation S-K and contained under the heading Election of Directors in the Notice of the 2011 Annual Meeting and 2011 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 2011 Annual Meeting of Stockholders (the 2011 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 2011 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 2011 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 2011 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 2011 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 2011 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 2011 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 2011 Proxy Statement shall not be deemed filed for purposes 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 2011 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 2011 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 2011 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 2011 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 2011 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 42 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		
	2010	**2009**	**2008**
Employee Termination Benefits:			
Balance at January 1	**$ 13**	$ 44	$ 117
Additions (deductions) charged (credited) to expense	**235**	(12)	(13)
Payments	**(103)**	(19)	(60)
Balance at December 31	**$ 145**	$ 13	$ 44
Allowance for Doubtful Accounts:			
Balance at January 1	**$ 293**	$ 275	$ 200
(Reductions) additions to expense	**(13)**	92	105
Bad debt write-offs	**(41)**	(74)	(30)
Balance at December 31	**$ 239**	$ 293	$ 275
Deferred Income Tax Valuation Allowance:*			
Balance at January 1	**$ 7,921**	$ 7,535	$ 5,949
Additions to deferred income tax expense	**1,454**	2,204	2,599
Reduction of deferred income tax expense	**(190)**	(1,818)	(1,013)
Balance at December 31	**$ 9,185**	$ 7,921	$ 7,535

* See also Note 15 to the Consolidated Financial Statements, beginning on page FS-47.

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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 24th day of February, 2011.

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 24th day of February, 2011.

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

Samuel H. Armacost*
Samuel H. Armacost

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.

Franklyn G. Jenifer*
Franklyn G. Jenifer

Sam Nunn*
Sam Nunn

Donald B. Rice*
Donald B. Rice

Kevin W. Sharer*
Kevin W. Sharer

Charles R. Shoemate*
Charles R. Shoemate

*By: /s/Lydia I. Beebe
Lydia I. Beebe,
Attorney-in-Fact

John G. Stumpf*
John G. Stumpf

Ronald D. Sugar*
Ronald D. Sugar

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	**2010**	2009	2008
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
Basic	**$ 9.53**	$ 5.26	$ 11.74
Diluted	**$ 9.48**	$ 5.24	$ 11.67
Dividends	**$ 2.84**	$ 2.66	$ 2.53
Sales and Other Operating Revenues	**$ 198,198**	$ 167,402	$ 264,958
Return on:			
Capital Employed	**17.4%**	10.6%	26.6%
Stockholders Equity	**19.3%**	11.7%	29.2%

Earnings by Major Operating Area

Millions of dollars	**2010**	2009	2008
Upstream[1]			
United States	**$ 4,122**	$ 2,262	$ 7,147
International	**13,555**	8,670	15,022
Total Upstream	**17,677**	10,932	22,169
Downstream[1]			
United States	**1,339**	(121)	1,369
International	**1,139**	594	1,783
Total Downstream	**2,478**	473	3,152
All Other	**(1,131)**	(922)	(1,390)
Net Income Attributable to Chevron Corporation[2,3]	**$19,024**	$10,483	$23,931

[1] 2009 and 2008 information has been revised to conform with the 2010 segment presentation.

[2] Includes foreign currency effects:	**$ (423)**	$ (744)	$ 862

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

The activities reported in Chevron s upstream and downstream operating segments have changed effective January 1, 2010. Results for the chemicals businesses are now reported as part of the downstream segment. In addition, the company s significant upstream-enabling operations, primarily a gas-to-liquids project and major international export pipelines, have been reclassified from the downstream segment to the upstream segment. Prior period information in this report has been revised to conform to the 2010 presentation.

Refer to the Results of Operations section beginning on page FS-7 for a discussion of financial results by major operating area for the three years ended December 31, 2010.

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 both segments is movement in the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. The overall trend in earnings is typically less affected by results from the company s other activities and investments. Earnings for the company in any period may also be influenced by events or transactions that are infrequent or unusual in nature.

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. 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.

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. 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. The company will continue to monitor these developments, take them into account in evaluating future investment opportunities, and otherwise seek to mitigate any risks to the company s current operations or future prospects.

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-7 for discussions of net gains on asset sales during 2010. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

In recent years, Chevron and the oil and gas industry generally experienced an increase in certain costs that exceeded the general trend of inflation in many areas of the world. This increase in costs affected the company s operating expenses and capital programs for all business segments, but particularly for Upstream. Softening of these cost pressures started in late 2008 and continued through most of 2009. Industry costs began to level out in fourth quarter 2009 and rose slightly in 2010. The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs.

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. The company remains confident of its underlying financial strength to address potential challenges presented in the current environment. (Refer also to the Liquidity and Capital Resources section beginning on page FS-12.)

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. Moreover, 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. Besides the impact of the fluctuation in prices for crude oil and natural gas, 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.

Price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can also 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 at the left shows the trend in benchmark prices for West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. The WTI price averaged $79 per barrel for the full-year 2010, compared to $62 in 2009. As of mid-February 2011, the WTI price was about $85.

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 number 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 2010 primarily due to both strong diesel prices and relatively weaker fuel oil prices.

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-11 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 $4.50 per thousand cubic feet (MCF) during 2010, compared with about $3.80 during 2009. As of mid-February 2011, the Henry Hub spot price was about $4.20 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 and the level of inventory in underground storage.

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

Certain international natural gas markets in which the company operates have different supply, demand and regulatory circumstances, which historically have resulted in lower average sales prices for the company s production of natural gas in these locations. In some of these locations Chevron is investing in long-term projects to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets where greater demand results in higher prices. International natural gas realizations averaged about $4.60 per MCF during 2010, compared with about $4.00 per MCF during 2009. These realizations reflect a strong demand for energy in certain Asian markets. (See page FS-11 for the company s average natural gas realizations for the U.S. and international regions.)

The company s worldwide net oil-equivalent production in 2010 averaged 2.763 million barrels per day. About one-fifth of the company s net oil-equivalent production in 2010 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 2010, while production in 2009 was reduced by an average of 20,000 barrels per day due to quotas imposed by OPEC. All of the imposed curtailments took place during the first half of 2009. At the December 2010 meeting, members of OPEC supported maintaining production quotas in effect since December 2008.

The company estimates that oil-equivalent production in 2011 will average approximately 2.790 million barrels per day. This estimate is subject to many factors and uncertainties, including additional quotas that may be imposed by OPEC, price effects on production volumes calculated under production sharing and variable-royalty provisions of certain agreements, 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-7 through FS-8 for additional discussion of the company s upstream business.

Refer to Table V beginning on page FS-71 for a tabulation of the company s proved net oil and gas reserves by geographic area, at the beginning of 2008 and each year-end from 2008 through 2010, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2010.

Gulf of Mexico Update In April 2010, an accident occurred on the Transocean Deepwater Horizon, a deepwater drilling rig in the Gulf of Mexico, resulting in a loss of life, the sinking of the rig and a significant oil spill. The rig was drilling an exploratory well at the BP-operated Macondo prospect. Chevron was not a participant in the well. Subsequent to the event, the U.S. Department of the Interior put in place a moratorium on the drilling of wells using subsea blowout preventers (BOPs) or surface BOPs on a floating facility in the Gulf of Mexico and the Pacific regions. In October 2010, the Secretary of the Interior lifted the drilling moratorium, provided that operators certify compliance with all the newly expanded rules and requirements, and demonstrate the availability of adequate blowout containment resources.

The moratorium and the ensuing slowdown in issuing drilling permits since the moratorium was lifted have resulted in delays in shallow water drilling activity, delayed the drilling of exploratory deepwater wells and impacted development drilling on both operated and nonoperated projects in the Gulf of Mexico. The company s daily net oil-equivalent production in the Gulf of Mexico was reduced by about 10,000 barrels per day for the full year. The company has submitted several deepwater drilling permit applications and plans to submit additional applications in 2011. Two deepwater drillships are on stand-by, pending issuance of permits from

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the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), to drill wells in the Gulf of Mexico. A third deepwater drillship is drilling a water injection well at the Tahiti Field. Additionally, the completion of previously drilled wells has recommenced at the nonoperated Perdido and Caesar/Tonga projects. The future effects of this incident, including any new or additional regulations that may be adopted and the timing of BOEMRE issuing drilling permits, are not fully known at this time. Chevron remains committed to deepwater exploration and development in the Gulf of Mexico and other deepwater basins around the world.

During the moratorium, Chevron participated in a number of industry efforts to identify opportunities to improve industry standards in prevention, intervention and spill response. In July 2010, Chevron and several other companies announced plans to build and deploy a rapid response system that will be available to capture and contain crude oil in the unlikely event of a future well blowout in the deepwater Gulf of Mexico. The new system will be engineered to be used in water depths up to 10,000 feet and designed to have capacity to contain 100,000 barrels per day, with potential for expansion. The companies committed to equally fund the initial $1 billion investment in the system. There will be additional ongoing costs for operations and maintenance of the system components. An initial agreement to secure containment equipment has been announced, and other equipment is expected to be secured and available in the coming months, with the new system targeted for completion in early 2012. The companies have formed an organization, the Marine Well Containment Company, to operate and maintain this system. Other companies have been invited and encouraged to participate in this organization.

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, cost 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 the 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, Latin America, Asia, southern Africa and the United Kingdom. Chevron operates or has significant ownership interests in refineries in each of these areas except Latin America. In third quarter 2010, the company completed its exit from the District of Columbia, Delaware, Indiana, Kentucky, North Carolina, New Jersey, Maryland, Ohio, Pennsylvania, South Carolina, Virginia, West Virginia and parts of Tennessee, where the company sold Chevron- and Texaco-branded motor fuels to retail customers through approximately 1,100 stations, and to commercial and industrial customers through supply arrangements. Sales in these markets represented approximately 8 percent of the company s total 2009 U.S. retail fuel sales volumes.

The company s refining and marketing margins in 2010 improved over 2009, but remain relatively weak due to the economic slowdown, excess refined product supplies and surplus refining capacity. Expecting these conditions to continue for several years, in first quarter 2010 the company announced that its downstream businesses would be restructured to improve operating efficiency and achieve sustained improvement in financial performance. As part of this restructuring, employee-reduction programs were announced for the United States and international downstream operations. The initial estimate included approximately 3,200 employees. Due to redeployment efforts within the company, it is currently expected that approximately 2,800 employees in the downstream operations will be terminated under these programs before the end of 2011. About 1,100 of the affected employees are located in the United States. During 2010, 1,400 employees were terminated worldwide. Refer to Note 23 of the Consolidated Financial Statements, beginning on page FS-59, for further discussion. In 2010, the company solicited bids for 13 U.S. terminals and certain operations in Europe (including the company s Pembroke Refinery), the Caribbean, and select

Central America and Africa markets. These sales are part of the company s ongoing effort to concentrate downstream resources and capital on strategic global assets. These potential market exits, dispositions of assets, and other actions may result in gains or losses in future periods. Through fourth quarter 2010, the company completed the sale of six U.S. terminals and certain marketing businesses in Africa, which resulted in gains that were not material to the company. Also, in late 2010 the company completed the sale of its 23.4 percent ownership interest in the Colonial Pipeline Company, which resulted in a gain on sale of nearly $400 million.

Refer to the Results of Operations section on page FS-9 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, alternative fuels, and technology companies. In first quarter 2010, employee-reduction programs were announced for the corporate staffs. As of year-end, it was expected that approximately 400 employees from the corporate staffs will be terminated under the programs by the end of 2011, including approximately 100 who were terminated in 2010. Refer to Note 23 of the Consolidated Financial Statements, beginning on page FS-59, for further discussion.

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Operating Developments

Key operating developments and other events during 2010 and early 2011 included the following:

Upstream

Australia Construction activities on Barrow Island and other activities for the Gorgon Project progressed on schedule during 2010 with the award of approximately $25 billion of contracts for materials and services, clearing of the plant site,
completion of the first stage of the construction village, commencement of module fabrication, and progression of studies on the possible expansion of the project. In early 2011, the company signed an additional binding liquefied natural gas (LNG) Sales and Purchase Agreement (SPA) with an Asian customer. The company has signed five binding LNG SPAs with Asian customers for delivery of about 4.7 million metric tons of LNG per year. Negotiations continue to finalize the two remaining nonbinding Heads of Agreement (HOAs) as binding SPAs, which would bring LNG delivery commitments to a combined total of about 90 percent of Chevron s share of LNG from the project.

Through the end of 2010, the company has signed nonbinding HOAs with three Asian customers for the delivery of about 80 percent of Chevron s net LNG offtake from the Chevron-operated Wheatstone Project. Negotiations continue to move the three HOAs to binding SPAs with these customers. These three customers have also agreed to acquire a combined 21.8 percent nonoperated working interest in the Wheatstone field licenses and a 17.5 percent interest in the foundation natural gas processing facilities at the time of the final investment decision. The project, currently undergoing front-end engineering and design (FEED), has a planned capacity of 8.9 million metric tons per year.

During 2010, the company announced additional deepwater natural gas discoveries, including the Clio and Acme prospects in 67 percent-owned Block WA-205-P, Yellowglen prospect in 50 percent-owned Block WA-268-P, Brederode prospect in 50 percent-owned Block WA-364-P,
and Sappho prospect in 50 percent-owned Block WA-392-P. In February 2011, the company announced a natural gas discovery in the Orthrus prospect in 50 percent-owned Block WA-24-R. These discoveries are expected to contribute to further growth at company-operated LNG projects in Australia.

Cambodia The company completed three successful exploration wells during 2010. In the first-half 2011, a 30-year production permit for the production sharing contract is expected to be approved by the government. A final investment decision for construction of a wellhead platform and a floating storage and offloading vessel is expected in 2011.

Canada First production was achieved from the Jackpine Mine in third quarter 2010 as a result of Athabasca Oil Sands Project Expansion 1 activities. In addition, through 2010 the company acquired approximately 200,000 acres of shale gas leasehold in western Canada. The appraisal of this acreage is expected to begin by the second-half 2011.

China The company acquired a 100 percent interest in Blocks 53-30 and 64-18, and a 59 percent interest in Block 42-05, covering a combined total exploratory acreage of approximately 5.2 million acres in the South China Sea s Pearl River Mouth Basin.

Indonesia A final investment decision was reached for Development Area 13 of the Duri Field, where Chevron holds a 100 percent working interest.

The company awarded FEED contracts in December 2010 for the Gendalo-Gehem natural gas development in the Makassar Strait offshore East Kalimantan, Indonesia. Contracts for floating production units, subsea and flowline systems, export pipelines, and an onshore receiving facility were awarded for the project.

Kazakhstan/Russia Approval was obtained from the shareholders and governing bodies of the Caspian Pipeline Consortium for a $5.4 billion expansion of the Caspian Pipeline. The capacity of the 935-mile pipeline, which carries crude oil from western Kazakhstan to a dedicated terminal on the Black Sea, will increase to 1.4 million barrels per day.

Liberia The company acquired a 70 percent interest and operatorship in three deepwater blocks covering 2.4 million acres off the coast of Liberia in western Africa. A three-year exploratory program began in fourth quarter 2010.

Poland Acquisition work commenced in October 2010 on a 2-D seismic survey across the company s four shale gas licenses in southeast Poland. Chevron has a 100 percent-owned and operated interest in these four concessions, totalling 1.1 million acres.

Republic of the Congo Discoveries were confirmed at the Bilondo Marine 2 and 3 wells within the Moho-Bilondo license. Chevron has a 31.5 percent interest in the permit area.

Romania The company successfully bid on three shale gas exploration blocks, comprising approximately 670,000 acres, in the southeast region of the country. In February

2011, the company acquired a 100 percent interest in the EV-2 Barlad shale gas concession, covering 1.5 million acres in the northeast region of the country.

Russia The company signed a nonbinding HOA for a deepwater development partnership on the Shatsky Ridge in the eastern Black Sea.

Turkey The company signed a Joint Operation Agreement for an exploration license in the Black Sea. Chevron acquired a 50 percent interest in a western portion of License 3921, a 5.6 million-acre block located 220 miles northwest of the capital city of Ankara.

United States In March 2010, first oil was achieved at the nonoperated Perdido Regional Development in the Gulf of Mexico. Located in nearly 8,000 feet of water, Perdido is also the world s deepest offshore oil and gas drilling and production spar. Chevron has a 37.5 percent working interest in the Perdido regional host facility.

The company sanctioned development of the Jack/St. Malo project in October 2010, the company s first operated project located in the Lower Tertiary trend in the deepwater Gulf of Mexico. Seven exploration and appraisal wells have been successfully and safely drilled at these fields since 2003. Chevron has a working interest of 50 percent in the Jack Field and 51 percent in the St. Malo Field.

In December 2010, the company sanctioned development of the 60 percent-owned and operated Big Foot project in the deepwater Gulf of Mexico.

In April 2010, the company successfully bid for new exploration acreage in a central Gulf of Mexico lease sale.

In February 2011, the company completed the acquisition of Atlas Energy, Inc., for $4.47 billion including assumed debt. Atlas holds one of the premier acreage positions in the Marcellus Shale, concentrated in southwestern Pennsylvania.

Venezuela In February 2010, a Chevron-led consortium was named the operator of the Carabobo 3 heavy-oil project, composed of three blocks in the Orinoco Oil Belt of eastern Venezuela. A joint operating company, Petroindependencia, was formed in May 2010, and work toward commercialization of the Carabobo 3 project was initiated. The consortium holds a combined 40 percent interest in the project.

Downstream

Africa In December 2010 and February 2011, the company completed the sale of its marketing businesses in Malawi, Mauritius, Réunion, Tanzania and Zambia.

Caribbean and Central America In November 2010, the company announced an agreement to sell its fuels marketing and aviation fuels businesses in Antigua, Barbados, Belize, Costa Rica, Dominica, French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Nicaragua, St. Kitts, St. Lucia, St. Vincent, and Trinidad and Tobago. The transactions are expected to close by third quarter 2011, following receipt of required local regulatory and government approvals. This sale is part of the company s ongoing effort to concentrate downstream resources and capital on strategic global assets.

Europe In February 2011, the company announced an agreement to sell its fuels, finished lubricants and aviation fuels businesses in Spain.

South Korea A new, 60,000-barrel-per-day heavy-oil hydrocracker was commissioned and reached full capacity in third quarter 2010 at the 50 percent-owned GS Caltex Yeosu Refinery in South Korea. Also at the Yeosu Refinery, GS Caltex announced plans to construct a 53,000-barrel-per-day gas oil fluid catalytic cracking unit. The unit is scheduled for start-up in 2013. Both units are designed to increase high-value product yield and lower feedstock costs.

United States In October 2010, the company sold its 23.4 percent ownership interest in the Colonial Pipeline Company.

In January 2011, the company announced the final investment decision on a $1.4 billion project to construct a lubricants manufacturing facility at the Pascagoula refinery. The facility will manufacture 25,000 barrels per day of premium base oil.

Other

Common Stock Dividends The quarterly common stock dividend increased by 5.9 percent in April 2010, to $0.72 per common share, making 2010 the 23rd consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program In July 2010, the company terminated the three-year $15 billion share repurchase program that had been initiated in September 2007. In its place, the Board of Directors approved a new, ongoing share repurchase program with no set term or monetary limits. The company began purchases of its common stock in the fourth quarter, and as of December 31, 2010, 8.8 million common shares had been acquired under the program for $750 million.

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-41, 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	**2010**	2009	2008
Earnings	**$ 4,122**	$ 2,262	$ 7,147

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.

U.S. upstream earnings of $2.3 billion in 2009 decreased $4.9 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by about $5.2 billion between periods,

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and gains on asset sales declined by approximately $900 million. Partially offsetting these effects was a benefit of about $1.3 billion resulting from an increase in net oil equivalent production. An approximate $600 million benefit to income from lower operating expenses was more than offset by higher depreciation expense. The benefit from lower operating expenses was largely associated with an absence of charges for damages related to the 2008 hurricanes in the Gulf of Mexico.

The company s average realization for U.S. crude oil and natural gas liquids in 2010 was $71.59 per barrel, compared with $54.36 in 2009 and $88.43 in 2008. The average natural gas realization was $4.26 per thousand cubic feet in 2010, compared with $3.73 and $7.90 in 2009 and 2008, respectively.

Net oil-equivalent production in 2010 averaged 708,000 barrels per day, down 1 percent from 2009 and up 6 percent from 2008. Natural field declines between 2010 and 2009 were mostly offset by increased production from the Tahiti Field. The increase between 2009 and 2008 was mainly due to the start-up of the Blind Faith Field in late 2008 and the Tahiti Field in second quarter 2009. The net liquids component of oil-equivalent production for 2010 averaged 489,000 barrels per day, up 1 percent from 2009 and up 16 percent compared with 2008. Net natural gas production averaged 1.3 billion cubic feet per day in 2010, down approximately 6 percent from 2009 and down about 12 percent from 2008. Refer to the Selected Operating Data table on page FS-11 for the three-year comparative production volumes in the United States.

International Upstream

Millions of dollars	**2010**	2009	2008
Earnings*	**$ 13,555**	$ 8,670	$ 15,022
*Includes foreign currency effects:	**$ (293)**	$ (578)	$ 937

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.

International upstream earnings of $8.7 billion in 2009 decreased $6.4 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by $7.0 billion, while foreign currency effects and higher operating and depreciation expenses decreased income by a total of $2.2 billion. Partially offsetting these items were benefits of $2.3 billion resulting from an increase in sales volumes of crude oil and about $500 million associated with asset sales and tax items related to the Gorgon Project.

The company s average realization for international crude oil and natural gas liquids in 2010 was $72.68 per barrel, compared with $55.97 in 2009 and $86.51 in 2008. The average natural gas realization was $4.64 per thousand cubic feet in 2010, compared with $4.01 and $5.19 in 2009 and 2008, respectively.

International net oil-equivalent production of 2.06 million barrels per day in 2010 increased about 3 percent and 11 percent from 2009 and 2008, respectively. The volumes in 2010 include synthetic oil that was reported in 2009 and 2008 as production from oil sands in Canada. Absent the impact of prices on certain production-sharing and variable-royalty agreements, net oil-equivalent production increased 5 percent in 2010 and 4 percent in 2009, when compared with the prior year s production.

The net liquids component of international oil-equivalent production was 1.4 million barrels per day in 2010, an increase of approximately 3 percent from 2009 and 14 percent from 2008. International net natural gas production of 3.7 billion cubic feet per day in 2010 was up 4 percent and 3 percent from 2009 and 2008, respectively.

Refer to the Selected Operating Data table, on page FS-11, for the three-year comparative of international production volumes.

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U.S. Downstream

Millions of dollars	**2010**	2009	2008
Earnings	**$ 1,339**	$ (121)	$ 1,369

U.S. downstream earned $1,339 million in 2010, compared with a loss of $121 million in 2009. Improved margins on refined products increased earnings by about $550 million. Also contributing to the increase was a nearly $400 million gain on the sale of a 23.4 percent ownership interest in the Colonial Pipeline Company. Higher earnings from chemicals operations increased earnings by about $300 million, largely from improved margins at the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem).

Earnings decreased approximately $1.5 billion in 2009 from 2008. Lower refined product margins resulted in an earnings decline of $1.7 billion. Partially offsetting the effects of lower refined product margins was a decrease in operating expenses, which benefited earnings by $300 million, and an increase of about $100 million in earnings from CPChem. The improvement for CPChem reflected lower utility and manufacturing costs, as well as the absence of an impairment recorded in 2008. These benefits more than offset lower margins on the sale of commodity chemicals.

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. Sales volumes of refined products were 1.40 million barrels per day in 2009, a decrease of 1 percent from 2008. U.S. branded gasoline sales decreased to 573,000 barrels per day in 2010, representing approximately 7 percent and 5 percent declines from 2009 and 2008, respectively. The decline in 2010, relative to 2009 and 2008, was primarily due to the previously announced exits from selected eastern U.S. retail markets.

Refer to the Selected Operating Data table on page FS-11 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

Millions of dollars	**2010**	2009	2008
Earnings*	**$1,139**	$ 594	$1,783
*Includes foreign currency effects:	**$ (135)**	$ (191)	$ 111

International downstream earned $1,139 million in 2010, compared with $594 million in 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 reduction and transportation costs. Foreign currency effects reduced earnings by $135 million in 2010, compared with a reduction of $191 million in 2009.

Earnings of $594 million in 2009 decreased about $1.2 billion from 2008. A decline of approximately $2.6 billion between periods was associated with weaker margins on the manufacture and sale of gasoline and other refined products and the absence of gains recorded in 2008 on derivative instruments. Foreign currency effects produced an unfavorable variance of about $300 million. Partially offsetting these items were a $1.0 billion benefit from lower operating expenses associated mainly with contract labor, professional services and transportation costs, and about a $550 million increase in gains on asset sales related to refined products marketing operations, primarily in certain countries in Latin America and Africa.

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. Refined product sales volumes of 1.85 million barrels per day in 2009 were 8 percent lower than in 2008, mainly due to the effects of asset sales and lower demand.

Refer to the Selected Operating Data table, on page FS-11, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

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All Other

Millions of dollars	**2010**	2009	2008
Net charges*	**$(1,131)**	$ (922)	$(1,390)
*Includes foreign currency effects:	**$ 5**	$ 25	$ (186)

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

Net charges in 2010 increased $209 million from 2009, mainly due to higher expenses for employee compensation and benefits and higher corporate tax items, partly offset by lower provisions for environmental remediation at sites that previously had been closed or sold. Net charges in 2009 decreased $468 million from 2008 due to lower provisions for environmental remediation at sites that previously had been closed or sold, favorable foreign currency effects and lower expenses for employee compensation and benefits.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2010**	2009	2008
Sales and other operating revenues	**$ 198,198**	$ 167,402	$ 264,958

Sales and other operating revenues increased in 2010, mainly due to higher prices for crude oil, natural gas and refined products. Lower 2009 prices resulted in decreased revenues compared with 2008.

Millions of dollars	**2010**	2009	2008
Income from equity affiliates	**$ 5,637**	$ 3,316	$ 5,366

Income from equity affiliates increased in 2010 from 2009 largely due to higher upstream-related earnings from Tengizchevroil (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. Income from equity affiliates decreased in 2009 from 2008. Upstream-related affiliate income declined about $1.3 billion mainly due to lower earnings for TCO as a result of lower prices for crude oil. Downstream-related affiliate earnings were lower by approximately $1.0 billion primarily due to weaker margins and an unfavorable swing in foreign currency effects. Refer to Note 12, beginning on page FS-43, for a discussion of Chevron s investments in affiliated companies.

Millions of dollars	**2010**	2009	2008
Other income	**$ 1,093**	$ 918	$ 2,681

Other income of $1.1 billion in 2010 included net gains of approximately $1.1 billion on asset sales. Other income in both 2009 and 2008 included net gains from asset sales of $1.3 billion. Interest income was approximately $120 million in 2010, $95 million in 2009 and $340 million in 2008. Foreign currency effects decreased other income by $251 million in 2010 and $466 million in 2009, while increasing other income by $355 million in 2008. In addition, other income in 2008 included approximately $700 million in favorable settlements and other items.

Millions of dollars	**2010**	2009	2008
Purchased crude oil and products	**$ 116,467**	$ 99,653	$ 171,397

Crude oil and product purchases in 2010 increased $16.8 billion from 2009 due to higher prices for crude oil, natural gas and refined products. Crude oil and product purchases in 2009 decreased $71.7 billion from 2008 due to lower prices for crude oil, natural gas and refined products.

Millions of dollars	**2010**	2009	2008
Operating, selling, general and administrative expenses	**$ 23,955**	$ 22,384	$ 26,551

Operating, selling, general and administrative 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. Total expenses for 2009 decreased approximately $4.2 billion from 2008 primarily due to $1.4 billion of lower fuel and transportation expenses; $800 million of decreased costs for contract labor and professional services; the absence of uninsured 2008 hurricane-related charges of $700 million; a decrease of about $500 million for environmental remediation activities; $200 million of lower costs for materials; and $600 million for other items.

Millions of dollars	**2010**	2009	2008
Exploration expense	**$ 1,147**	$ 1,342	$ 1,169

Exploration expenses in 2010 declined from 2009 mainly due to lower amounts for geological and geophysical costs and well write-offs. Exploration expenses in 2009 increased from 2008 mainly due to higher amounts for well write-offs in the United States and international operations.

Millions of dollars	**2010**	2009	2008
Depreciation, depletion and amortization	**$ 13,063**	$ 12,110	$ 9,528

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. Depreciation, depletion and amortization expenses increased in 2009 from 2008 due to incremental production related to start-ups for upstream projects in the United States and Africa and higher depreciation rates for certain other oil and gas producing fields.

Millions of dollars	**2010**	2009	2008
Taxes other than on income	**$ 18,191**	$ 17,591	$ 21,303

Taxes other than on income increased in 2010 from 2009 mainly due to higher excise taxes in Canada and the United Kingdom. Taxes other than on income decreased in 2009 from 2008 mainly due to lower import duties for the company s downstream operations in the United Kingdom.

Millions of dollars	**2010**	2009	2008
Interest and debt expense	**$ 50**	$ 28	$

Interest and debt expense, net of capitalized interest, increased in 2010 from 2009 primarily due to slightly higher average effective interest rates. The increase in 2009 over 2008 was due to an increase in long-term debt.

Millions of dollars	**2010**	2009	2008
Income tax expense	**$ 12,919**	$ 7,965	$ 19,026

Effective income tax rates were 40 percent in 2010, 43 percent in 2009 and 44 percent in 2008. The rate was lower in 2010 than in 2009 primarily due to international upstream impacts. A lower effective tax rate in international upstream in 2010 was primarily driven by 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. The rate was lower in 2009 than in 2008 mainly due to the effect in 2009 of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates. Refer also to the discussion of income taxes in Note 15 beginning on page FS-47.

Selected Operating Data[1,2]

	2010	2009	2008
U.S. Upstream			

Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	**489**	484	421
Net Natural Gas Production (MMCFPD)[3]	**1,314**	1,399	1,501
Net Oil-Equivalent Production (MBOEPD)	**708**	717	671
Sales of Natural Gas (MMCFPD)	**5,932**	5,901	7,226
Sales of Natural Gas Liquids (MBPD)	**22**	17	15
Revenues From Net Production			
Liquids ($/Bbl)	**$ 71.59**	$ 54.36	$ 88.43
Natural Gas ($/MCF)	**$ 4.26**	$ 3.73	$ 7.90
International Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)[4]	**1,434**	1,362	1,228
Net Natural Gas Production (MMCFPD)[3]	**3,726**	3,590	3,624
Net Oil-Equivalent			
Production (MBOEPD)[5]	**2,055**	1,987	1,859
Sales of Natural Gas (MMCFPD)	**4,493**	4,062	4,215
Sales of Natural Gas Liquids (MBPD)	**27**	23	17
Revenues From Liftings			
Liquids ($/Bbl)	**$ 72.68**	$ 55.97	$ 86.51
Natural Gas ($/MCF)	**$ 4.64**	$ 4.01	$ 5.19
Worldwide Upstream			
Net Oil-Equivalent Production			
(MBOEPD)[3,5]			
United States	**708**	717	671
International	**2,055**	1,987	1,859
Total	**2,763**	2,704	2,530
U.S. Downstream			
Gasoline Sales (MBPD)[6]	**700**	720	692
Other Refined Product Sales (MBPD)	**649**	683	721
Total Refined Product Sales (MBPD)	**1,349**	1,403	1,413
Sales of Natural Gas Liquids (MBPD)	**139**	144	144
Refinery Input (MBPD)	**890**	899	891
International Downstream			
Gasoline Sales (MBPD)[6]	**521**	555	589
Other Refined Product Sales (MBPD)	**1,243**	1,296	1,427
Total Refined Product Sales (MBPD)[7]	**1,764**	1,851	2,016
Sales of Natural Gas Liquids (MBPD)	**78**	88	97
Refinery Input (MBPD)	**1,004**	979	967

[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	**62**	58	70
International	**475**	463	450
[4] Includes: Canada synthetic oil	**24**		
Venezuela affiliate synthetic oil	**28**		
[5] Includes Canada oil sands		26	27
[6] Includes branded and unbranded gasoline.			
[7] Includes sales of affiliates (MBPD):	**562**	516	512

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Liquidity and Capital Resources

Cash, cash equivalents, time deposits and marketable securities Total balances were $17.1 billion and $8.8 billion at December 31, 2010 and 2009, respectively. Cash provided by operating activities in 2010 was $31.4 billion, compared with $19.4 billion in 2009 and $29.6 billion in 2008. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.4 billion, $1.7 billion and $800 million in 2010, 2009 and 2008, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.0 billion in 2010, $2.6 billion in 2009 and $1.5 billion in 2008. Cash provided by operating activities during 2010 was more than sufficient to fund the company s $21.8 billion capital and exploratory program, pay $5.7 billion of dividends to shareholders and repurchase $750 million of common stock.

Restricted cash of $855 million and $123 million associated with various capital-investment projects at December 31, 2010 and 2009, 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 $5.7 billion in 2010, $5.3 billion in 2009 and $5.2 billion in 2008. In April 2010, the company increased its quarterly common stock dividend by 5.9 percent, to $0.72 per share.

Debt and capital lease obligations Total debt and capital lease obligations were $11.5 billion at December 31, 2010, up from $10.5 billion at year-end 2009.

The $1.0 billion increase in total debt and capital lease obligations during 2010 included issuance of $1.25 billion of tax-exempt bonds, partially offset by a decrease in short-term obligations. 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 $5.6 billion at December 31, 2010, up from $4.6 billion at year-end 2009. Of this amount, $5.4 billion and $4.2 billion were reclassified to long-term at the end of each period, respectively. At year-end 2010, settlement of these obligations was not expected to require the use of working capital in 2011, 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, 2010, the company had $6.0 billion in committed credit facilities with various major banks, expiring in May 2013, 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, 2010. 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, Texaco Capital Inc. and Union Oil Company of California. 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-1 by Moody s. All of these ratings denote high-quality, investment-grade securities.

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

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Capital and Exploratory Expenditures

			2010			2009			2008
Millions of dollars	U.S.	Int l.	Total	U.S.	Int l.	Total	U.S.	Int l.	Total
Upstream	**$ 3,450**	**$ 15,454**	**$ 18,904**	$ 3,294	$ 15,002	$ 18,296	$ 5,648	$ 12,713	$ 18,361
Downstream	**1,456**	**1,096**	**2,552**	2,087	1,449	3,536	2,457	1,332	3,789
All Other	**286**	**13**	**299**	402	3	405	618	7	625
Total	**$ 5,192**	**$ 16,563**	**$ 21,755**	$ 5,783	$ 16,454	$ 22,237	$ 8,723	$ 14,052	$ 22,775
Total, Excluding Equity in Affiliates	**$ 4,934**	**$ 15,433**	**$ 20,367**	$ 5,558	$ 15,094	$ 20,652	$ 8,241	$ 12,228	$ 20,469

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 company terminated the $15 billion share repurchase program initiated in September 2007. No share repurchases occurred in 2010 under the program prior to its termination. From the inception of the program, the company acquired 119 million shares at a cost of $10.1 billion. In its place, the Board of Directors approved a new, ongoing share repurchase program with no set term or monetary limits. The company expects to repurchase between $500 million and $1 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. The company began purchases of its common stock in the fourth quarter, and through December 31, 2010, 8.8 million shares were purchased under the new program for $750 million.

Capital and exploratory expenditures Total expenditures for 2010 were $21.8 billion, including $1.4 billion for the company s share of equity-affiliate expenditures. In 2009 and 2008, expenditures were $22.2 billion and $22.8 billion, respectively, including the company s share of
affiliates expenditures of $1.6 billion and $2.3 billion, respectively, and $2 billion for the extension of an upstream concession in 2009.

Of the $21.8 billion of expenditures in 2010, 87 percent, or $18.9 billion, was related to upstream activities. Approximately 80 percent was expended for upstream operations in 2009 and 2008. International upstream accounted for about 82 percent of the worldwide upstream investment in 2010, about 80 percent in 2009 and about 70 percent in 2008, reflecting the company s continuing focus on opportunities available outside the United States.

The company estimates that in 2011, capital and exploratory expenditures will be $26.0 billion, including $2.0 billion of spending by affiliates. Approximately 85 percent of the total, or $22.6 billion, is budgeted for exploration and produc-
tion activities, with $17.2 billion of this amount for projects outside the United States. Spending in 2011 is primarily focused on major development projects in Angola, Australia, Brazil, Canada, China, Nigeria, Thailand, the United Kingdom and the U.S. Gulf of Mexico. Also included is funding for base business improvements and focused exploration and appraisal programs in core hydrocarbon basins.

Worldwide downstream spending in 2011 is estimated at $2.9 billion, with about $1.7 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and South Korea.

Investments in technology, power generation and other corporate businesses in 2011 are budgeted at $500 million.

Noncontrolling interests The company had noncontrolling interests of $730 million and $647 million at December 31, 2010 and 2009, respectively. Distributions to noncontrolling interests totaled $72 million and $71 million in 2010 and 2009, respectively.

Pension Obligations In 2010, the company s pension plan contributions were $1.4 billion (including $1.19 billion to the U.S. plans and $258 million to the international plans). The company estimates contributions in 2011 will be approximately $950 million ($650 million for the U.S. plans and $300 million for the international plans). Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in Critical Accounting Estimates and Assumptions, beginning on page FS-20.

Financial Ratios

Financial Ratios

	At December 31		
	2010	2009	2008
Current Ratio	**1.7**	1.4	1.1
Interest Coverage Ratio	**101.7**	62.3	166.9
Debt Ratio	**9.8%**	10.3%	9.3%

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 2010, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $7.0 billion.

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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 2010 was higher than 2009 due to higher before-tax income. The company s interest coverage ratio in 2009 was lower than 2008 due to lower 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 2010 and 2009 was due to a higher Chevron Corporation stockholders equity balance. The increase in 2009 over 2008 was primarily due to the increase in debt.

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

Direct Guarantee

Millions of dollars			Commitment Expiration by Period		
			2012	2014	After
	Total	2011	2013	2015	2015
Guarantee of non-consolidated affiliate or joint-venture obligation	$ 613	$	$ 76	$ 77	$ 460

The company s guarantee of approximately $600 million is associated with certain payments under a terminal use agreement entered into by a company affiliate. The terminal is expected to be operational by 2012. Over the approximate 16-year term of the guarantee, the maximum guarantee amount will be reduced over time as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of any amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company s interests in those investments. The
company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300 million. Through the end of 2010, the company had paid $48 million under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco s ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described in the preceding paragraph are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any applicable incident.

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. The acquirer of those assets shared in certain environmental remediation costs up to a maximum obligation of $200 million, which had been reached at December 31, 2009. Under the indemnification agreement, after reaching the $200 million obligation, Chevron is solely responsible until

April 2022, when the indemnification expires. The environmental conditions or events that are subject to these indemnities must have arisen prior to the sale of the assets in 1997.

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity,

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drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company s business. The aggregate approximate amounts of required payments under these various commitments are: 2011 $17.2 billion; 2012 $4.1 billion; 2013 $3.5 billion; 2014 $3.1 billion; 2015 $3.0 billion; 2016 and after $7.7 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $6.5 billion in 2010, $8.1 billion in 2009 and $5.1 billion in 2008.

The following table summarizes the company s significant contractual obligations:

Contractual Obligations[1]

Millions of dollars				Payments Due by Period	
	Total	2011	2012 2013	2014 2015	After 2015
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 187	$ 187	$	$	$
Long-Term Debt[3]	11,003		6,940	2,020	2,043
Noncancelable Capital Lease Obligations	488	99	161	91	137
Interest	2,208	299	486	320	1,103
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,836	650	900	561	725
Throughput and Take-or-Pay Agreements	34,127	16,305	5,592	4,727	7,503
Other Unconditional Purchase Obligations[4]	4,420	913	2,004	1,343	160

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page FS-52.

2 Does not include amounts related to the company s income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates for the periods in which these liabilities may become payable. The company does

not expect settlement of such liabilities will have a material effect on its results of operations, consolidated financial position or liquidity in any single period.

[3] $5.4 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2012-2013 period.

[4] Does not include obligations to purchase the company s share of natural gas liquids and regasified natural gas associated with operations of the 36.4 percent-owned Angola LNG affiliate. The LNG plant is expected to commence operations in 2012 and is designed to produce 5.2 million metric tons of LNG and related natural gas liquids per year. Volumes and prices associated with these purchase obligations are neither fixed nor determinable.

Financial and Derivative Instruments

The market risk associated with the company s portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk discussed below do not represent the company s projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading Risk Factors in Part I, Item 1A, of the company s 2010 Annual Report on Form 10-K.

Derivative Commodity Instruments Chevron is exposed to market risks related to the price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of these activities were not material to the company s financial position, results of operations or cash flows in 2010.

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

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

Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes. The change in fair value of Chevron s derivative commodity instruments in 2010 was a quarterly average decrease of $1 million in total assets and a quarterly average increase of $18 million in total liabilities.

The company uses a Value-at-Risk (VaR) model to estimate the potential loss in fair value on a single day from the effect of adverse changes in market conditions on derivative commodity instruments held or issued, which are recorded on the balance sheet at December 31, 2010, as derivative commodity instruments in accordance with accounting standards for derivatives (ASC 815). VaR is the maximum loss not to be exceeded within a given probability or confidence level over a given period of time. The company s VaR model uses the Monte Carlo simulation method that involves generating hypothetical scenarios from the specified probability distributions and constructing a full distribution of a portfolio s potential values.

The VaR model utilizes an exponentially weighted moving average for computing historical volatilities and correlations, a 95 percent confidence level, and a one-day holding period. That is, the company s 95 percent, one-day VaR corresponds to the unrealized loss in portfolio value that would not be exceeded on average more than one in every 20 trading days, if the portfolio were held constant for one day.

The one-day holding period is based on the assumption that market-risk positions can be liquidated or hedged within one day. For hedging and risk management, the company uses conventional exchange-traded instruments such as futures and options as well as non-exchange-traded swaps, most of which can be liquidated or hedged effectively within one day. The following table presents the 95 percent/one-day VaR for each of the company s primary risk exposures in the area of derivative commodity instruments at December 31, 2010 and 2009.

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Millions of dollars	**2010**	2009
Crude Oil	**$ 15**	$ 17
Natural Gas	**4**	4
Refined Products	**14**	19

Foreign Currency The company may enter into foreign currency derivative contracts to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments. The foreign currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open foreign currency derivative contracts at December 31, 2010.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Interest rate swaps, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2010, the company had no interest rate swaps.

Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements and long-term purchase agreements. Refer to Other Information in Note 12 of the Consolidated Financial Statements, page FS-43, for further discussion. Management believes these agreements have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

Litigation and Other Contingencies

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 19 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company s ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

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

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

In 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $18.9 billion, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer s report also asserted that an additional $8.4 billion could be assessed against Chevron for unjust enrichment. In 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case was recused. In 2010, Chevron moved to strike the mining engineer s report and to dismiss the case based on evidence obtained through discovery in the United States indicating that the report was prepared by con-

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sultants for the plaintiffs before being presented as the mining engineer s independent and impartial work and showing further evidence of misconduct. In August 2010, the judge issued an order stating that he was not bound by the mining engineer s report and requiring the parties to provide their positions on damages within 45 days. Chevron subsequently petitioned for recusal of the judge, claiming that he had disregarded evidence of fraud and misconduct and that he had failed to rule on a number of motions within the statutory time requirement.

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

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador s obligations under the United States-Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador s obligations under the BIT. On February 9, 2011, the Permanent Court of Arbitration issued an Order for Interim Measures requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. Chevron expects to continue seeking permanent injunctive relief and monetary relief before the Tribunal.

Through a series of recent U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron has obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron is seeking relief that includes an award of damages and a declaration that any judgment against Chevron in the Lago Agrio litigation is the result of fraud and other unlawful conduct and is therefore unenforceable. On February 8, 2011, the Court issued a temporary restraining order prohibiting the Lago Agrio plaintiffs and persons acting in concert with them from taking any action in furtherance of recognition or enforcement of any judgment against Chevron in the Lago Agrio case until March 8, 2011. Chevron s motion for a preliminary injunction is presently before the Court.

On February 14, 2011, the Provincial Court in Lago Agrio rendered an adverse judgment in the case. The Provincial Court rejected Chevron s defenses to the extent the Court addressed them in its opinion. The judgment assesses approximately $8.6 billion in damages and about $0.9 billion for the plaintiffs representatives. It also assesses an additional amount of approximately $8.6 billion in punitive damages unless the company provides a public apology. Chevron continues to believe the Court s judgment is illegitimate and unenforceable in Ecuador, the United States and other countries. The company also believes the judgment is the product of fraud, and contrary to the legitimate scientific evidence. Chevron will appeal this decision in Ecuador. Chevron cannot predict the timing or ultimate outcome of the appeals process in Ecuador. Chevron will continue a vigorous defense of any imposition of liability. Because Chevron has no substantial assets in Ecuador, Chevron would expect enforcement actions as a result of this judgment to be brought in other jurisdictions. Chevron expects to contest any such actions.

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

Environmental The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company s liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company s competitive position relative to other U.S. or international petroleum or chemical companies.

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

Millions of dollars	**2010**	2009	2008
Balance at January 1	**$ 1,700**	$ 1,818	$ 1,539
Net Additions	**220**	351	784
Expenditures	**(413)**	(469)	(505)
Balance at December 31	**$ 1,507**	$ 1,700	$ 1,818

Included in the $1,507 million year-end 2010 reserve balance were remediation activities at approximately 182 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company s remediation reserve for these sites at year-end 2010 was $185 million. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties costs at designated hazardous waste sites are not expected to have a material effect on the company s results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2010 environmental reserves balance of $1,322 million, $814 million related to the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facilities, and pipelines. The remaining $508 million was associated with various sites in international downstream ($100 million), upstream ($329 million) and other businesses ($79 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company s plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2010 had a recorded liability that was material to the company s results of operations, consolidated financial position or liquidity.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company s liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

The company records asset obligations when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. These asset retirement obligations include costs related to environmental issues. The liability balance of approximately $12.5 billion for asset retirement obligations at year-end 2010 related primarily to upstream properties.

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

Refer also to Note 25 on page FS-62, related to the company s asset retirement obligations and the discussion of Environmental Matters on page FS-19.

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 15 beginning on page FS-47 for a discussion of the periods for which tax returns have been audited for the company s major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

Suspended Wells The company suspends the costs of exploratory wells pending a final determination of the commercial potential of the related crude oil and natural gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity or development decisions or both. At December 31, 2010, the company had approximately $2.7 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $283 million from 2009. The 2009 balance reflected an increase of $317 million from 2008.

The future trend of the company s exploration expenses can be affected by amounts associated with well write-offs, including wells that had been previously suspended pending determination as to whether the well had found reserves that could be classified as proved. The effect on exploration expenses in future periods of the $2.7 billion of suspended wells at year-end 2010 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page FS-50, for additional discussion of suspended wells.

Equity Redetermination For crude oil and natural gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron s interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately $200 million, and the possible maximum net amount that could be owed to Chevron is estimated at about $150 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies On April 26, 2010, a California appeals court issued a ruling related to the adequacy of an Environmental Impact Report (EIR) supporting the issuance of certain permits by the city of Richmond, California, to replace and upgrade certain facilities at Chevron s refinery in
Richmond. Settlement discussions with plaintiffs in the case ended late fourth quarter 2010, and the company continues to evaluate its options going forward, which may include requesting the city to revise the EIR to address the issues identified by the Court of Appeal or other actions. Management believes the outcomes associated with the potential options for the project are uncertain. Due to the uncertainty of the company s future course of action, or potential outcomes of any action or combination of actions, management does not believe an estimate of the financial effects, if any, of the ruling can be made at this time. However, the company s ultimate exposure may be significant to net income in any one future period.

Chevron receives claims from and submits claims to customers; trading partners; U.S. federal, state and local regulatory bodies; governments; contractors; insurers; and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

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

Environmental Matters

Virtually all aspects of the businesses in which the company engages are subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to increase in both number and complexity over time and govern not only the manner in which the company conducts its operations, but also the products it sells. Most of the costs of complying with laws and regulations pertaining to company operations and products are embedded in the normal costs of doing business.

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. In addition to the costs for environmental protection associated with its ongoing operations and products, the company may incur expenses for corrective actions at various owned and previously owned facilities and at third-party-owned waste disposal sites used by the company. An obligation may arise when operations are closed or sold or at non-Chevron sites where company products have been handled or disposed of. Most of the expenditures to fulfill these obligations relate to facilities and sites where past operations followed practices and procedures that were considered acceptable at the time but now require investigative or remedial work or both to meet current standards.

Using definitions and guidelines established by the American Petroleum Institute, Chevron estimated its worldwide environmental spending in 2010 at approximately $2.9 billion for its consolidated companies. Included in these expenditures were approximately $1.4 billion of environmental capital expenditures and $1.5 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

For 2011, total worldwide environmental capital expenditures are estimated at $1.5 billion. These capital costs are

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in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

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

Critical Accounting Estimates and Assumptions

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

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

1. the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and

2. the impact of the estimates and assumptions on the company s financial condition or operating performance is material.

Besides those meeting these critical criteria, the company makes many other accounting estimates and assumptions in preparing its financial statements and related disclosures. Although not associated with highly uncertain matters, these estimates and assumptions are also subject to revision as circumstances warrant, and materially different results may sometimes occur.

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be more likely than not. Another example is the estimation of crude oil and natural gas reserves under SEC rules, which require ...by
analysis of geosciences and engineering data, (the reserves) can be estimated with reasonable certainty to be economically producible...under existing economic conditions where existing economic conditions include prices based on the average price during the 12-month period prior to the end of the reporting period. Refer to Table V, Reserve Quantity Information, beginning on page FS-71, for the changes in these estimates for the three years ending December 31, 2010, and to Table VII, Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves on page FS-80 for estimates of proved-reserve values for each of the three years ended December 31, 2010. Note 1 to the Consolidated Financial Statements, beginning on page FS-32, includes a description of the successful efforts method of accounting for oil and gas exploration and production activities. The estimates of crude oil and natural gas reserves are important to the timing of expense recognition for costs incurred.

The discussion of the critical accounting policy for Impairment of Properties, Plant and Equipment and Investments in Affiliates, beginning on page FS-22, includes reference to conditions under which downward revisions of proved-reserve quantities could result in impairments of oil and gas properties. This commentary should be read in conjunction with disclosures elsewhere in this discussion and in the Notes to the Consolidated Financial Statements related to estimates, uncertainties, contingencies and new accounting standards. Significant accounting policies are discussed in Note 1 to the Consolidated Financial Statements, beginning on page FS-32. The development and selection of accounting estimates and assumptions, including those deemed critical, and the associated disclosures in this discussion have been discussed by management with the Audit Committee of the Board of Directors.

The areas of accounting and the associated critical estimates and assumptions made by the company are as follows:

Pension and Other Postretirement Benefit Plans The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. For other postretirement benefit (OPEB) plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining OPEB obligations and expense are the discount rate and the assumed health care cost-trend rates.

Note 21, beginning on page FS-52, includes information on the funded status of the company s pension and OPEB plans at the end of 2010 and 2009; the components of pension and OPEB expense for the three years ending December 31, 2010; and the underlying assumptions for those periods.

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Pension and OPEB expense is reported on the Consolidated Statement of Income as Operating expenses or Selling, general and administrative expenses and applies to all business segments. The year-end 2010 and 2009 funded status, measured as the difference between plan assets and obligations, of each of the company s pension and OPEB plans is recognized on the Consolidated Balance Sheet. The differences related to overfunded pension plans are reported as a long-term asset in Deferred charges and other assets. The differences associated with underfunded or unfunded pension and OPEB plans are reported as Accrued liabilities or Reserves for employee benefit plans. Amounts yet to be recognized as components of pension or OPEB expense are reported in Accumulated other comprehensive loss.

To estimate the long-term rate of return on pension assets, the company uses a process that incorporates actual historical asset-class returns and an assessment of expected future performance and takes into consideration external actuarial advice and asset-class factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company s estimates of long-term rates of return are consistent with these studies. The expected long-term rate of return on U.S. pension plan assets, which account for 70 percent of the company s pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2010, actual asset returns averaged 4.7 percent for this plan. The actual return for 2010 was 11.6 percent and was associated with the broad recovery in the financial markets.

The year-end market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market value in the preceding three months, as opposed to the maximum allowable period of five years under U.S. accounting rules. Management considers the three-month period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of year-end is used in calculating the pension expense.

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2010, the company selected a 4.8 percent discount rate for the major U.S. pension plan and 5.0 percent for its OPEB plan. These rates were selected based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2010. The discount rates at the end of 2009 were 5.3 percent for the major U.S. pension plan and 5.8 percent for the company s U.S. OPEB plan, and 6.3 percent at the end of 2008 for both the U.S. pension and OPEB plans.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2010 was $1.1 billion. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the
company s primary U.S. pension plan would have reduced total pension plan expense for 2010 by approximately $65 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 61 percent of the companywide pension obligation, would have reduced total pension plan expense for 2010 by approximately $140 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan reported on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2010, for underfunded plans was approximately $3.3 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company s primary U.S. pension plan would have reduced the plan obligation by approximately $300 million, which would have decreased the plan s underfunded status from approximately $0.9 billion to $0.6 billion. Other plans would be less underfunded as discount rates increase. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world s financial markets.

In 2010, the company s pension plan contributions were $1.45 billion (including $1.19 billion to the U.S. plans). In 2011, the company estimates contributions will be approximately $950 million. Actual contribution amounts are dependent upon investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

For the company s OPEB plans, expense for 2010 was $166 million and the total liability, which reflected the unfunded status of the plans at the end of 2010, was $3.6 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2010, a 1 percent increase in the discount rate for the company s primary U.S. OPEB plan, which accounted for about 69 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $15 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 85 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2010 by approximately $80 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 8 percent in 2011 and gradually drop to 5 percent for 2018 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2010, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for 85 percent of the companywide OPEB liabilities, would have increased OPEB expense by $8 million.

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are not included in benefit plan costs in the year the difference occurs. Instead, the differences are

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included in actuarial gain/loss and unamortized amounts have been reflected in Accumulated other comprehensive loss on the Consolidated Balance Sheet. Refer to Note 21, beginning on page FS-52, for information on the $6.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2010; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2011.

Impairment of Properties, Plant and Equipment and Investments in Affiliates The company assesses its properties, plant and equipment (PP&E) for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in the company s business plans, changes in commodity prices and, for crude oil and natural gas properties, significant downward revisions of estimated proved reserve quantities. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its estimated fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters, such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles, and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, commodity chemicals and refined products. However, the impairment reviews and calculations are based on assumptions that are consistent with the company s business plans and long-term investment decisions. Refer also to the discussion of impairments of properties, plant and equipment in Note 9 beginning on page FS-37.

No major individual impairments of PP&E and Investments were recorded for the three years ending December 31, 2010. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company s PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for impairment when the fair value of the investment falls below the company s carrying value. When such a decline is deemed to be other than temporary, an impairment charge is recorded to the income statement for the difference between the investment s carrying value and its estimated fair value at the time.

In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee s financial performance, and the company s ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment s market value. Differing assumptions could affect whether an investment is impaired in any period or the amount of the impairment, and are not subject to sensitivity analysis.

From time to time, the company performs impairment reviews and determines whether any write-down in the carrying value of an asset or asset group is required. For example, when significant downward revisions to crude oil and natural gas reserves are made for any single field or concession, an impairment review is performed to determine if the carrying value of the asset remains recoverable. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed of. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets associated carrying values.

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by accounting standards for goodwill (ASC 350), the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as Operating expenses or Selling, general and administrative expenses on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is more likely than not (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 15 beginning on page FS-47. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2010.

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

New Accounting Standards

Transfers and Servicing (ASC 860), Accounting for Transfers of Financial Assets (ASU 2009-16) The FASB issued ASU 2009-16 in December 2009. This standard became effective for the company on January 1, 2010. ASU 2009-16 changes how companies account for transfers of financial assets and eliminates the concept of qualifying special-purpose entities. Adoption of the guidance did not have an effect on the company s results of operations, financial position or liquidity.

Consolidation (ASC 810), Improvements to Financial Reporting by Enterprises Involved With Variable Interest Entities (ASU 2009-17) The FASB issued ASU 2009-17 in December 2009. This standard became effective for the company January 1, 2010. ASU 2009-17 requires the enterprise to qualitatively assess if it is the primary beneficiary of a variable-interest entity (VIE), and if so, the VIE must be consolidated. Adoption of the standard did not have an impact on the company s results of operations, financial position or liquidity.

Receivables (ASC 310), Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses (ASU 2010-20) In July 2010, the FASB issued ASU 2010-20, which became effective with the company s reporting at December 31, 2010. This standard amends and expands disclosure requirements about the credit quality of financing receivables and the related allowance for credit losses. As a result of these amendments, companies are required to disaggregate, by portfolio segment or class of financing receivable, certain existing disclosures and provide certain new disclosures about financing receivables and related allowance for credit losses. Adoption of the standard did not change the company s existing disclosures.

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Quarterly Results and Stock Market Data
Unaudited

				2010				2009
illions of dollars, except per-share amounts	**4th Q**	**3rd Q**	**2nd Q**	**1st Q**	4th Q	3rd Q	2nd Q	1st Q
evenues and Other Income								
ales and other operating revenues[1]	**$ 51,852**	**$ 48,554**	**$ 51,051**	**$ 46,741**	$ 47,588	$ 45,180	$ 39,647	$ 34,987
ncome from equity affiliates	**1,510**	**1,242**	**1,650**	**1,235**	898	1,072	735	611
ther income	**665**	**(78)**	**303**	**203**	190	373	(177)	532
otal Revenues and Other Income	**54,027**	**49,718**	**53,004**	**48,179**	48,676	46,625	40,205	36,130
osts and Other Deductions								
urchased crude oil and products	**30,109**	**28,610**	**30,604**	**27,144**	28,606	26,969	23,678	20,400
perating expenses	**5,343**	**4,665**	**4,591**	**4,589**	4,899	4,403	4,209	4,346
elling, general and administrative expenses	**1,408**	**1,181**	**1,136**	**1,042**	1,330	1,177	1,043	977
xploration expenses	**335**	**420**	**212**	**180**	281	242	438	381
epreciation, depletion and amortization	**3,439**	**3,401**	**3,141**	**3,082**	3,156	2,988	3,099	2,867
axes other than on income[1]	**4,623**	**4,559**	**4,537**	**4,472**	4,583	4,644	4,386	3,978
nterest and debt expense	**4**	**9**	**17**	**20**		14	6	8
otal Costs and Other Deductions	**45,261**	**42,845**	**44,238**	**40,529**	42,855	40,437	36,859	32,957
ncome Before Income Tax Expense	**8,766**	**6,873**	**8,766**	**7,650**	5,821	6,188	3,346	3,173
ncome Tax Expense	**3,446**	**3,081**	**3,322**	**3,070**	2,719	2,342	1,585	1,319
et Income	**$ 5,320**	**$ 3,792**	**$ 5,444**	**$ 4,580**	$ 3,102	$ 3,846	$ 1,761	$ 1,854
ess: Net income attributable to oncontrolling interests	**25**	**24**	**35**	**28**	32	15	16	17
et Income Attributable to Chevron Corporation	**$ 5,295**	**$ 3,768**	**$ 5,409**	**$ 4,552**	$ 3,070	$ 3,831	$ 1,745	$ 1,837
er Share of Common Stock								
et Income Attributable to Chevron Corporation								
Basic	**$ 2.65**	**$ 1.89**	**$ 2.71**	**$ 2.28**	$ 1.54	$ 1.92	$ 0.88	$ 0.92
Diluted	**$ 2.64**	**$ 1.87**	**$ 2.70**	**$ 2.27**	$ 1.53	$ 1.92	$ 0.87	$ 0.92
ividends	**$ 0.72**	**$ 0.72**	**$ 0.72**	**$ 0.68**	$ 0.68	$ 0.68	$ 0.65	$ 0.65
ommon Stock Price Range High[2,3]	**$ 92.39**	**$ 82.19**	**$ 83.41**	**$ 81.09**	$ 79.82	$ 73.37	$ 72.75	$ 78.45
Low[2,3]	**$ 80.41**	**$ 66.83**	**$ 67.80**	**$ 69.55**	$ 67.87	$ 60.88	$ 63.06	$ 56.12

Includes excise, value-added and similar taxes:	**$ 2,136**	**$ 2,182**	**$ 2,201**	**$ 2,072**	$ 2,086	$ 2,079	$ 2,034	$ 1,910

Intraday price.
2009 conformed with 2010 presentation.

The company s common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 18, 2011, stockholders of record numbered approximately 186,000. There are no restrictions on the company s ability to pay dividends.

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Management s Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

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

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

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

Management s Report on Internal Control Over Financial Reporting

The company s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company s management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company s internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company s management concluded that internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of the company s internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

John S. Watson	Patricia E. Yarrington	Matthew J. Foehr
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller
February 24, 2011		

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, comprehensive income, equity and of cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2010 and December 31, 2009 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating
the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP
San Francisco, California
February 24, 2011

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Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2010	2009	2008
Revenues and Other Income			
Sales and other operating revenues*	**$ 198,198**	$ 167,402	$ 264,958
Income from equity affiliates	**5,637**	3,316	5,366
Other income	**1,093**	918	2,681
Total Revenues and Other Income	**204,928**	171,636	273,005
Costs and Other Deductions			
Purchased crude oil and products	**116,467**	99,653	171,397
Operating expenses	**19,188**	17,857	20,795
Selling, general and administrative expenses	**4,767**	4,527	5,756
Exploration expenses	**1,147**	1,342	1,169
Depreciation, depletion and amortization	**13,063**	12,110	9,528
Taxes other than on income*	**18,191**	17,591	21,303
Interest and debt expense	**50**	28	
Total Costs and Other Deductions	**172,873**	153,108	229,948
Income Before Income Tax Expense	**32,055**	18,528	43,057
Income Tax Expense	**12,919**	7,965	19,026
Net Income	**19,136**	10,563	24,031
Less: Net income attributable to noncontrolling interests	**112**	80	100
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
Basic	**$ 9.53**	$ 5.26	$ 11.74
Diluted	**$ 9.48**	$ 5.24	$ 11.67
*Includes excise, value-added and similar taxes.	**$ 8,591**	$ 8,109	$ 9,846

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2010	2009	2008
Net Income	**$ 19,136**	$ 10,563	$ 24,031
Currency translation adjustment			
Unrealized net change arising during period	**6**	60	(112)
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(4)**	2	(6)
Derivatives			
Net derivatives gain (loss) on hedge transactions	**25**	(69)	139
Reclassification to net income of net realized loss (gain)	**5**	(23)	32
Income taxes on derivatives transactions	**(10)**	32	(61)
Total	**20**	(60)	110
Defined benefit plans			
Actuarial loss			
Amortization to net income of net actuarial loss	**635**	575	483
Actuarial loss arising during period	**(857)**	(1,099)	(3,228)
Prior service cost			
Amortization to net income of net prior service credits	**(61)**	(65)	(64)
Prior service cost arising during period	**(12)**	(34)	(32)
Defined benefit plans sponsored by equity affiliates	**(12)**	65	(97)
Income taxes on defined benefit plans	**140**	159	1,037
Total	**(167)**	(399)	(1,901)
Other Comprehensive Loss, Net of Tax	**(145)**	(397)	(1,909)
Comprehensive Income	**18,991**	10,166	22,122
Comprehensive income attributable to noncontrolling interests	**(112)**	(80)	(100)
Comprehensive Income Attributable to Chevron Corporation	**$ 18,879**	$ 10,086	$ 22,022

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Balance Sheet

Millions of dollars, except per-share amounts

	At December 31	
	2010	2009
Assets		
Cash and cash equivalents	**$ 14,060**	$ 8,716
Time deposits	**2,855**	
Marketable securities	**155**	106
Accounts and notes receivable (less allowance: 2010 $184; 2009 $228)	**20,759**	17,703
Inventories:		
Crude oil and petroleum products	**3,589**	3,680
Chemicals	**395**	383
Materials, supplies and other	**1,509**	1,466
Total inventories	**5,493**	5,529
Prepaid expenses and other current assets	**5,519**	5,162
Total Current Assets	**48,841**	37,216
Long-term receivables, net	**2,077**	2,282
Investments and advances	**21,520**	21,158
Properties, plant and equipment, at cost	**207,367**	188,288
Less: Accumulated depreciation, depletion and amortization	**102,863**	91,820
Properties, plant and equipment, net	**104,504**	96,468
Deferred charges and other assets	**3,210**	2,879
Goodwill	**4,617**	4,618
Total Assets	**$ 184,769**	$ 164,621
Liabilities and Equity		
Short-term debt	**$ 187**	$ 384
Accounts payable	**19,259**	16,437
Accrued liabilities	**5,324**	5,375
Federal and other taxes on income	**2,776**	2,624
Other taxes payable	**1,466**	1,391
Total Current Liabilities	**29,012**	26,211
Long-term debt	**11,003**	9,829
Capital lease obligations	**286**	301
Deferred credits and other noncurrent obligations	**19,264**	17,390
Noncurrent deferred income taxes	**12,697**	11,521
Reserves for employee benefit plans	**6,696**	6,808
Total Liabilities	**78,958**	72,060
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)		
	1,832	1,832

Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2010 and 2009)		
Capital in excess of par value	**14,796**	14,631
Retained earnings	**119,641**	106,289
Accumulated other comprehensive loss	**(4,466)**	(4,321)
Deferred compensation and benefit plan trust	**(311)**	(349)
Treasury stock, at cost (2010 435,195,799 shares; 2009 434,954,774 shares)	**(26,411)**	(26,168)
Total Chevron Corporation Stockholders Equity	**105,081**	91,914
Noncontrolling interests	**730**	647
Total Equity	**105,811**	92,561
Total Liabilities and Equity	**$ 184,769**	$ 164,621

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2010	2009	2008
Operating Activities			
Net Income	**$ 19,136**	$ 10,563	$ 24,031
Adjustments			
Depreciation, depletion and amortization	**13,063**	12,110	9,528
Dry hole expense	**496**	552	375
Distributions less than income from equity affiliates	**(501)**	(103)	(440)
Net before-tax gains on asset retirements and sales	**(1,004)**	(1,255)	(1,358)
Net foreign currency effects	**251**	466	(355)
Deferred income tax provision	**559**	467	598
Net decrease (increase) in operating working capital	**76**	(2,301)	(1,673)
Increase in long-term receivables	**(12)**	(258)	(161)
Decrease (increase) in other deferred charges	**48**	201	(84)
Cash contributions to employee pension plans	**(1,450)**	(1,739)	(839)
Other	**697**	670	10
Net Cash Provided by Operating Activities	**31,359**	19,373	29,632
Investing Activities			
Capital expenditures	**(19,612)**	(19,843)	(19,666)
Proceeds and deposits related to asset sales	**1,995**	2,564	1,491
Net purchases of time deposits	**(2,855)**		
Net (purchases) sales of marketable securities	**(49)**	127	483
Repayment of loans by equity affiliates	**338**	336	179
Net (purchases) sales of other short-term investments	**(732)**	244	432
Net Cash Used for Investing Activities	**(20,915)**	(16,572)	(17,081)
Financing Activities			
Net (payments) borrowings of short-term obligations	**(212)**	(3,192)	2,647
Proceeds from issuances of long-term debt	**1,250**	5,347	
Repayments of long-term debt and other financing obligations	**(156)**	(496)	(965)
Cash dividends common stock	**(5,674)**	(5,302)	(5,162)
Distributions to noncontrolling interests	**(72)**	(71)	(99)
Net (purchases) sales of treasury shares	**(306)**	168	(6,821)
Net Cash Used for Financing Activities	**(5,170)**	(3,546)	(10,400)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**70**	114	(166)
Net Change in Cash and Cash Equivalents	**5,344**	(631)	1,985
Cash and Cash Equivalents at January 1	**8,716**	9,347	7,362

Cash and Cash Equivalents at December 31	**$ 14,060**	$ 8,716	$ 9,347

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Equity
Shares in thousands; amounts in millions of dollars

	2010		2009		2008	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred Stock		**$**		$		$
Common Stock	**2,442,677**	**$ 1,832**	2,442,677	$ 1,832	2,442,677	$ 1,832
Capital in Excess of Par						
Balance at January 1		**$ 14,631**		$ 14,448		$ 14,289
Treasury stock transactions		**165**		183		159
Balance at December 31		**$ 14,796**		$ 14,631		$ 14,448
Retained Earnings						
Balance at January 1		**$ 106,289**		$ 101,102		$ 82,329
Net income attributable to Chevron Corporation		**19,024**		10,483		23,931
Cash dividends on common stock		**(5,674)**		(5,302)		(5,162
Tax benefit from dividends paid on unallocated ESOP shares and other		**2**		6		4
Balance at December 31		**$ 119,641**		$ 106,289		$ 101,102
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (111)**		$ (171)		$ (59
Change during year		**6**		60		(112
Balance at December 31		**$ (105)**		$ (111)		$ (171
Pension and other postretirement benefit plans						
Balance at January 1		**$ (4,308)**		$ (3,909)		$ (2,008
Change to defined benefit plans during year		**$ (167)**		(399)		(1,901
Balance at December 31		**$ (4,475)**		$ (4,308)		$ (3,909
Unrealized net holding gain on securities						
Balance at January 1		**$ 15**		$ 13		$ 19
Change during year		**(4)**		2		(6
Balance at December 31		**$ 11**		$ 15		$ 13
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 83**		$ 143		$ 33
Change during year		**20**		(60)		110
Balance at December 31		**$ 103**		$ 83		$ 143
Balance at December 31		**$ (4,466)**		$ (4,321)		$ (3,924

Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ (109)**		$ (194)		$ (214
Net reduction of ESOP debt and other		**38**		85		20
Balance at December 31		**(71)**		(109)		(194
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240
Balance at December 31	**14,168**	**$ (311)**	14,168	$ (349)	14,168	$ (434
Treasury Stock at Cost						
Balance at January 1	**434,955**	**$ (26,168)**	438,445	$ (26,376)	352,243	$ (18,892
Purchases	**9,091**	**(775)**	85	(6)	95,631	(8,011
Issuances mainly employee benefit plans	**(8,850)**	**532**	(3,575)	214	(9,429)	527
Balance at December 31	**435,196**	**$ (26,411)**	434,955	$ (26,168)	438,445	$ (26,376
Total Chevron Corporation Stockholders Equity at December 31		**$ 105,081**		$ 91,914		$ 86,648
Noncontrolling Interests		**$ 730**		$ 647		$ 469
Total Equity		**$ 105,811**		$ 92,561		$ 87,117

See accompanying Notes to the Consolidated Financial Statements.

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Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

Note 1
Summary of Significant Accounting Policies
General Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; liquefaction, transportation and regasification associated with liquefied natural gas (LNG); transporting crude oil by major international oil export pipelines; processing, transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations relate primarily to 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 additives for fuels and lubricant oils.

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

The nature of the company s operations and the many countries in which it operates subject the company to changing economic, regulatory and political conditions. The company does not believe it is vulnerable to the risk of near-term severe impact as a result of any concentration of its activities.

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

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

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

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

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

Inventories Crude oil, petroleum products and chemicals inventories are generally stated at cost, using a last-in, first-out

Note 1 Summary of Significant Accounting Policies - Continued
(LIFO) method. In the aggregate, these costs are below market. Materials, supplies and other inventories generally are stated at average cost.

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 19, beginning on page FS-50, for additional discussion of accounting for suspended exploratory well costs.

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

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value. Refer to Note 9, beginning on page FS-37, relating to fair value measurements.

As required under accounting standards for asset retirement obligations (Accounting Standards Codification (ASC) 410), the fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 25, on page FS-62, relating to AROs.

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

Depreciation and depletion expenses for mining assets are determined using the unit-of-production method as the proved reserves are produced. The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method generally is used to depreciate international plant and equipment and to amortize all capitalized leased assets.

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

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

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by accounting standards for goodwill (ASC 350), the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company s U.S. and Canadian marketing facilities, the accrual

Note 1 Summary of Significant Accounting Policies - Continued

is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and mineral-producing properties, a liability for an ARO is made, following accounting standards for asset retirement and environmental obligations. Refer to Note 25, on page FS-62, for a discussion of the company s AROs.

For federal Superfund sites and analogous sites under state laws, the company records a liability for its designated share of the probable and estimable costs and probable amounts for other potentially responsible parties when mandated by the regulatory agencies because the other parties are not able to pay their respective shares.

The gross amount of environmental liabilities is based on the company s best estimate of future costs using currently available technology and applying current regulations and the company s own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

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

Revenue Recognition Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized on the entitlement method. Excise, value-added and similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income on page FS-27. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in Purchased crude oil and products on the Consolidated Statement of Income.

Stock Options and Other Share-Based Compensation The company issues stock options and other share-based compensation to its employees and accounts for these transactions under the accounting standards for share-based compensation (ASC 718). For equity awards, such as stock options, total compensation cost is based on the grant date fair value, and for liability awards, such as stock appreciation rights, total compensation cost is based on the settlement value. The company recognizes stock-based compensation expense for all awards over the service period required to earn the award, which is the shorter of the vesting period or the time period an employee becomes eligible to retain the award at retirement. Stock options and stock appreciation rights granted under the company s Long-Term Incentive Plan have graded vesting provisions by which one-third of each award vests on the first, second and third anniversaries of the date of grant. The company amortizes these graded awards on a straight-line basis.

Note 2

Agreement to Acquire Atlas Energy, Inc.

In November 2010, Chevron announced plans to acquire Atlas Energy, Inc. The acquisition was completed in February 2011 for $4,470, including assumed debt. The acquisition will be accounted for as a business combination (ASC 805). Atlas holds one of the premier acreage positions in the Marcellus Shale, concentrated in southwestern Pennsylvania.

Note 3

Noncontrolling Interests

The company adopted accounting standards for noncontrolling interests (ASC 810) in the consolidated financial statements effective January 1, 2009, and retroactive to the earliest period presented. Ownership interests in the company s subsidiaries held by parties other than the parent are presented separately from the parent s equity on the Consolidated Balance Sheet. The amount of consolidated net income attributable to the parent and the noncontrolling interests are both presented on the face of the Consolidated Statement of Income. The term earnings is defined as Net

Income Attributable to Chevron Corporation.

Activity for the equity attributable to noncontrolling interests for 2010, 2009 and 2008 is as follows:

	2010	2009	2008
Balance at January 1	**$ 647**	$ 469	$ 204
Net income	**112**	80	100
Distributions to noncontrolling interests	**(72)**	(71)	(99)
Other changes, net	**43**	169	264
Balance at December 31	**$ 730**	$ 647	$ 469

Note 4
Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2010	2009	2008
Net decrease (increase) in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	**$ (2,767)**	$ (1,476)	$ 6,030
Decrease (increase) in inventories	**15**	1,213	(1,545)
Increase in prepaid expenses and other current assets	**(542)**	(264)	(621)
Increase (decrease) in accounts payable and accrued liabilities	**3,049**	(1,121)	(4,628)
Increase (decrease) in income and other taxes payable	**321**	(653)	(909)
Net decrease (increase) in operating working capital	**$ 76**	$ (2,301)	$ (1,673)
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$ 34**	$	$
Income taxes	**$ 11,749**	$ 7,537	$ 19,130
Net sales of marketable securities consisted of the following gross amounts:			
Marketable securities sold	**$ 41**	$ 157	$ 3,719
Marketable securities purchased	**(90)**	(30)	(3,236)
Net (purchases) sales of marketable securities	**$ (49)**	$ 127	$ 483
Net purchases of time deposits consisted of the following gross amounts:			
Time deposits purchased	**$ (5,060)**	$	$
Time deposits matured	**2,205**		
Net purchases of time deposits	**$ (2,855)**	$	$

In accordance with accounting standards for cash-flow classifications for stock options (ASC 718), the Net decrease (increase) in operating working capital includes reductions of $67, $25 and $106 for excess income tax benefits associated with stock options exercised during 2010, 2009 and 2008, respectively. These amounts are offset by an equal amount in Net (purchases) sales of treasury shares.

The Net (purchases) sales of treasury shares represents the cost of common shares purchased less the cost of shares issued for share-based compensation plans. Purchases totaled $775, $6 and $8,011 in 2010, 2009 and 2008, respectively. Purchases in 2010 and 2008 included shares purchased under the company s common stock repurchase programs.

In 2010, Net (purchases) sales of other short-term investments consist of restricted cash associated with capital-investment projects at the company s Pascagoula and El Segundo refineries and the Angola liquefied natural gas project that was invested in short-term securities and reclassified from Cash and cash equivalents to Deferred charges and other assets on the Consolidated Balance Sheet. The company issued $1,250 and $350, in 2010 and 2009, respectively, of tax exempt bonds as a source of funds for U.S. refinery projects.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2008, Net (purchases) sales of treasury shares excludes $680 of treasury shares acquired in exchange for a U.S. upstream property and $280 in cash. The carrying value of this property in Properties, plant and equipment on the Consolidated Balance Sheet was not significant. In 2008, a $2,450 increase in Accrued liabilities and a corresponding increase to Properties, plant and equipment, at cost were considered noncash transactions and excluded from Net decrease (increase) in operating working capital and Capital expenditures. In 2009, the payments related to these Accrued liabilities were excluded from Net decrease (increase) in operating working capital and were reported as Capital expenditures. The amount is related to upstream operating agreements outside the United States. Capital expenditures in 2008 excludes a $1,400 increase in Properties, plant and equipment related to the acquisition of an additional interest in an equity affiliate that required a change to the consolidated method of accounting for the investment during 2008. This addition was offset primarily by reductions in Investments and advances and working capital and an increase in Non-current deferred income tax liabilities. Refer also to Note 25, on page FS-62, for a discussion of revisions to the company s AROs that also did not involve cash receipts or payments for the three years ending December 31, 2010.

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

	Year ended December 31		
	2010	2009	2008
Additions to properties, plant and equipment[1]	**$ 18,474**	$ 16,107	$ 18,495
Additions to investments	**861**	942	1,051
Current year dry hole expenditures	**414**	468	320
Payments for other liabilities and assets, net[2]	**(137)**	2,326	(200)
Capital expenditures	**19,612**	19,843	19,666
Expensed exploration expenditures	**651**	790	794
Assets acquired through capital lease obligations and other financing obligations	**104**	19	9
Capital and exploratory expenditures, excluding equity affiliates	**20,367**	20,652	20,469
	1,388	1,585	2,306

Company s share of expenditures by equity affiliates			
Capital and exploratory expenditures, including equity affiliates	**$ 21,755**	$ 22,237	$ 22,775

[1] Excludes noncash additions of $2,753 in 2010, $985 in 2009 and $5,153 in 2008.

[2] 2009 includes payments of $2,450 for accruals recorded in 2008.

Note 5

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

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

During 2008, Chevron implemented legal reorganizations in which certain Chevron subsidiaries transferred assets to or under CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the table below gives retroactive effect to the reorganizations as if they had occurred on January 1, 2008. However, the financial information in the following table may not reflect the financial position and operating results in the future or the historical results in the periods presented if the reorganization actually had occurred on that date. The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2010	2009	2008
Sales and other operating revenues	**$ 145,381**	$ 121,553	$ 195,593
Total costs and other deductions	**139,984**	120,053	185,788
Net income attributable to CUSA	**4,159**	1,141	7,318

	At December 31	
	2010	2009
Current assets	**$ 29,211**	$ 23,286
Other assets	**35,294**	32,827
Current liabilities	**18,098**	16,098
Other liabilities	**16,785**	14,625
Total CUSA net equity	**29,622**	25,390
Memo: Total debt	**$ 8,284**	$ 6,999

The Net income attributable to CUSA for the year ended December 31, 2008, has been adjusted by an immaterial amount associated with the allocation of income-tax liabilities among Chevron Corporation subsidiaries.

Note 6

Summarized Financial Data Chevron Transport Corporation Ltd.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of Chevron Corporation. CTC is the principal operator of Chevron s international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC s shipping revenue is derived from providing transportation services to other Chevron companies. Chevron Corporation has fully and unconditionally guaranteed this subsidiary s obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2010	2009	2008
Sales and other operating revenues	**$ 885**	$ 683	$ 1,022
Total costs and other deductions	**1,008**	810	947
Net (loss) income attributable to CTC	**(116)**	(124)	120

	At December 31	
	2010	2009
Current assets	**$ 209**	$ 377
Other assets	**201**	173
Current liabilities	**101**	115
Other liabilities	**75**	90
Total CTC net equity	**234**	345

There were no restrictions on CTC s ability to pay dividends or make loans or advances at December 31, 2010.

Note 7

Summarized Financial Data Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 12, on page FS-43, for a discussion of TCO operations.

Summarized financial information for 100 percent of TCO is presented in the following table:

	Year ended December 31		
	2010	2009	2008
Sales and other operating revenues	**$ 17,812**	$ 12,013	$ 14,329
Costs and other deductions	**8,394**	6,044	5,621
Net income attributable to TCO	**6,593**	4,178	6,134

	At December 31	
	2010	2009
Current assets	**$ 3,376**	$ 3,190
Other assets	**11,813**	12,022
Current liabilities	**2,402**	2,426
Other liabilities	**4,130**	4,484
Total TCO net equity	**8,657**	8,302

Note 8

Lease Commitments

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

	At December 31	
	2010	2009
Upstream	**$ 561**	$ 510
Downstream	**316**	334
All Other	**169**	169
Total	**1,046**	1,013
Less: Accumulated amortization	**573**	585
Net capitalized leased assets	**$ 473**	$ 428

Rental expenses incurred for operating leases during 2010, 2009 and 2008 were as follows:

	Year ended December 31		
	2010	2009	2008
Minimum rentals	**$ 2,373**	$ 2,179	$ 2,984
Contingent rentals	**10**	7	6
Total	**2,383**	2,186	2,990
Less: Sublease rental income	**41**	41	41
Net rental expense	**$ 2,342**	$ 2,145	$ 2,949

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

At December 31, 2010, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases

Year: 2011	650	99
2012	530	93
2013	370	68
2014	288	51
2015	273	40
Thereafter	725	137
Total	$ 2,836	$ 488
Less: Amounts representing interest and executory costs		(105)
Net present values		383
Less: Capital lease obligations included in short-term debt		(97)
Long-term capital lease obligations		$ 286

Note 9

Fair Value Measurements

Accounting standards for fair value measurement (ASC 820) establish a framework for measuring fair value and stipulate disclosures about fair value measurements. The standards apply to recurring and nonrecurring financial and nonfinancial assets and liabilities that require or permit fair value measurements. Among the required disclosures is the fair value hierarchy of inputs the company uses to value an asset or a liability. The three levels of the fair value hierarchy are described as follows:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities. For the company, Level 1 inputs include exchange-traded futures contracts for which the parties are willing to transact at the exchange-quoted price and marketable securities that are actively traded.

Level 2: Inputs other than Level 1 that are observable, either directly or indirectly. For the company, Level 2 inputs include quoted prices for similar assets or liabilities, prices obtained through third-party broker quotes, and prices that can be corroborated with other observable inputs for substantially the complete term of a contract.

Level 3: Unobservable inputs. The company does not use Level 3 inputs for any of its recurring fair value measurements. Level 3 inputs may be required for the determination of fair value associated with certain nonrecurring measurements of nonfinancial assets and liabilities. In 2010, the company used Level 3 inputs to determine the fair value of certain nonrecurring nonfinancial assets.

Note 9 Fair Value Measurements - Continued

The fair value hierarchy for recurring assets and liabilities measured at fair value at December 31, 2010, and December 31, 2009, is as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2010	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	At December 31, 2009	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Marketable securities	**$ 155**	**$155**	**$**	**$**	$ 106	$106	$	$
Derivatives	**122**	**11**	**111**		127	14	113	
Total Recurring Assets at Fair Value	**$ 277**	**$166**	**$ 111**	**$**	$ 233	$120	$ 113	$
Derivatives	**$ 171**	**$ 75**	**$ 96**	**$**	$ 101	$ 20	$ 81	$
Total Recurring Liabilities at Fair Value	**$ 171**	**$ 75**	**$ 96**	**$**	$ 101	$ 20	$ 81	$

Marketable Securities The company calculates fair value for its marketable securities based on quoted market prices for identical assets and liabilities. The fair values reflect the cash that would have been received if the instruments were sold at December 31, 2010.

Derivatives The company records its derivative instruments other than any commodity derivative contracts that are designated as normal purchase and normal sale on the Consolidated Balance Sheet at fair value, with virtually all the offsetting amount on the Consolidated Statement of Income. For derivatives with identical or similar provisions as contracts that are publicly traded on a regular basis, the company uses the market values of the publicly traded instruments as an input for fair value calculations.

The company s derivative instruments principally include crude oil, natural gas and refined product futures, swaps, options and forward contracts. Derivatives classified as Level 1 include futures, swaps and options contracts traded in active markets such as the New York Mercantile Exchange.

Derivatives classified as Level 2 include swaps, options, and forward contracts principally with financial institutions and other oil and gas companies, the fair values for which are obtained from third-party broker quotes, industry pricing services and exchanges. The company obtains multiple sources of pricing information for the Level 2 instruments. Since this pricing information is generated from observable market data, it has historically been very

consistent. The company does not materially adjust this information. The company incorporates internal review, evaluation and assessment procedures, including a comparison of Level 2 fair values derived from the company s internally developed for-
ward curves (on a sample basis) with the pricing information to document reasonable, logical and supportable fair value determinations and proper level of classification.

Impairments of Properties, plant and equipment In accordance with the accounting standard for the impairment or disposal of long-lived assets (ASC 360), during 2010 and 2009 long-lived assets held and used with carrying amounts of $142 and $949 were written down to fair values of $57 and $490 resulting in before-tax losses of $85 and $459, respectively. The fair values were determined from internal cash flow models, using discount rates consistent with those used by the company to evaluate cash flows of other assets of a similar nature.

Long-lived assets held for sale with carrying amounts of $49 and $160 were written down to a fair value of $13 and $68, resulting in a before-tax loss of $36 and $92 in 2010 and 2009, respectively. The fair values were determined based on bids received from prospective buyers and from internal cash-flow models consistent with those used by the company to evaluate cash flows of other assets of a similar nature.

Impairments of Investments and advances In accordance with the accounting standards under the equity method of accounting (ASC 323) and the cost method of accounting (ASC 325), during 2010 and 2009 investments with carrying amounts of $15 and $81 were written down to fair values of $0 and $39 resulting in before-tax losses of $15 and $42, respectively. The fair values were determined using discount rates consistent with those used by the company to evaluate cash flows of other investments of a similar nature.

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Note 9 Fair Value Measurements - Continued

The fair value hierarchy for nonrecurring assets and liabilities measured at fair value during 2010 is presented in the following table:

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

	Year ended December 31 2010	Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Loss (Before Tax) Year ended December 31 2010	Year ended December 31 2009	Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Loss (Before Tax) Year ended December 31 2009
Properties, plant and equipment, net (held and used)	**$ 57**	**$**	**$**	**$ 57**	**$ 85**	$ 490	$	$	$ 490	$ 459
Properties, plant and equipment, net (held for sale)	**13**			**13**	**36**	68		68		92
Investments and advances					**15**	39			39	42
Total Nonrecurring Assets at Fair Value	**$ 70**	**$**	**$**	**$ 70**	**$ 136**	$ 597	$	$ 68	$ 529	$ 593

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents and bank time deposits in U.S. and non-U.S. portfolios. The instruments classified as cash equivalents are primarily bank time deposits with maturities of 90 days or less and money market funds. Cash and cash equivalents had carrying/fair values of $14,060 and $8,716 at December 31, 2010 and December 31, 2009, respectively. The instruments held in Time deposits are bank time deposits with maturities greater than 90 days and had carrying/fair values of $2,855 at December 31, 2010. The fair values of cash, cash equivalents and bank time deposits reflect the cash that would have been received or paid if the instruments were settled at year-end.

Cash and cash equivalents do not include investments with a carrying/fair value of $855 and $123 at December 31, 2010 and December 31, 2009, respectively. These investments are restricted funds related to an international upstream development project and U.S. refinery projects, which are reported in Deferred charges and other assets on the Consolidated Balance Sheet. Long-term debt of $5,636 and $5,705 had estimated fair values of $6,311 and $6,229 at December 31, 2010 and December 31, 2009, respectively.

The carrying values of short-term financial assets and liabilities on the balance sheet approximate their fair values. Fair values of other financial instruments at the end of 2010 and 2009 were not material.

Note 10

Financial and Derivative Instruments

Derivative Commodity Instruments Chevron is exposed to market risks related to price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. From time to time, the company also uses derivative commodity instruments for limited trading purposes.

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

The company uses International Swaps and Derivatives Association agreements to govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transactions, bilateral collateral arrangements may also be required. When the company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable netting agreement with that counterparty, the net mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and is a reasonable measure of the company s credit risk exposure. The company also uses other netting agreements with certain counterparties with which it conducts significant transactions to mitigate credit risk.

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Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

Note 10 Financial and Derivative Instruments - Continued

Derivative instruments measured at fair value at December 31, 2010, December 31, 2009 and December 31, 2008, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are as follows:
Consolidated Balance Sheet: Fair Value of Derivatives Not Designated as Hedging Instruments

	Asset Derivatives Fair Value			Liability Derivatives Fair Value		
Type of Derivative Contract	Balance Sheet Classification	At December 31 2010	At December 31 2009	Balance Sheet Classification	At December 31 2010	At December 31 2009
Commodity	Accounts and notes receivable, net	**$ 58**	$ 99	Accrued payable	**$ 131**	$ 73
Commodity	Long-term receivable, net	**64**	28	Deferred credits and other noncurrent obligations	**40**	28
		$ 122	$ 127		**$ 171**	$ 101

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

		Gain/(Loss) Year ended December 31		
Type of Derivative Contract	Statement of Income Classification	**2010**	2009	2008
Foreign Exchange	Other income	**$**	$ 26	$ (314)
Commodity	Sales and other operating revenues	**(98)**	(94)	706
Commodity	Purchased crude oil and products	**(36)**	(353)	424
Commodity	Other income	**(1)**		(3)
		$ (135)	$ (421)	$ 813

Foreign Currency The company may enter into currency derivative contracts to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments. The currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open currency derivative contracts at December 31, 2010 or 2009.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Interest rate swaps related to a portion of the company s fixed-rate debt, if any, may be accounted for as fair value hedges. Interest rate swaps related to floating-rate debt, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2010 and 2009, the company had no interest rate swaps.

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

The trade receivable balances, reflecting the company s diversified sources of revenue, are dispersed among the company s broad customer base worldwide. As a result, the company believes concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, requiring Letters of Credit is a principal method used to support sales to customers.

Note 11

Operating Segments and Geographic Data

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. The investments are grouped into two business segments, Upstream and Downstream, representing the company s reportable segments and operating segments as defined in accounting standards for segment reporting (ASC 280). Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; liquefaction, transportation and regasification associated with liquefied natural gas (LNG); transporting crude oil by major international oil export pipelines; processing, transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations consist primarily of refining of crude oil into petroleum products; marketing of crude oil and refined products; transporting of crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant additives. All Other activities of the company include mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, and alternative fuels and technology.

The segments are separately managed for investment purposes under a structure that includes segment managers who report to the company s chief operating decision maker (CODM) (terms as defined in ASC 280). The CODM is the company s Executive Committee (EXCOM), a committee of senior officers that includes the Chief Executive Officer, and EXCOM reports to the Board of Directors of Chevron Corporation.

The operating segments represent components of the company, as described in accounting standards for segment reporting (ASC 280), that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and assesses their performance; and (c) for which discrete financial information is available.

Segment managers for the reportable segments are directly accountable to and maintain regular contact with the company s CODM to discuss the segment s operating activities and financial performance. The CODM approves annual capital and exploratory budgets at the reportable segment level, as well as reviews capital and exploratory funding for major projects and approves major changes to the annual capital and exploratory budgets. However, business-unit managers within the operating segments are directly responsible for decisions relating to project implementation and all other matters connected with daily operations. Company officers who are members of the EXCOM also have individual management responsibilities and participate in other committees for purposes other than acting as the CODM.

The activities reported in Chevron s upstream and downstream operating segments have changed effective January 1, 2010. Chemicals businesses are now reported as part of the downstream segment. In addition, the company s significant upstream-enabling operations, primarily a gas-to-liquids project and major international export pipelines, have been reclassified from the downstream segment to the upstream segment. Prior period information in this report has been revised to conform to the 2010 presentation.

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

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

	Year ended December 31		
	2010	2009	2008
Segment Earnings			

Upstream			
United States	**$ 4,122**	$ 2,262	$ 7,147
International	**13,555**	8,670	15,022
Total Upstream	**17,677**	10,932	22,169
Downstream			
United States	**1,339**	(121)	1,369
International	**1,139**	594	1,783
Total Downstream	**2,478**	473	3,152
Total Segment Earnings	**20,155**	11,405	25,321
All Other			
Interest expense	**(41)**	(22)	
Interest income	**70**	46	192
Other	**(1,160)**	(946)	(1,582)
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931

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Note 11 Operating Segments and Geographic Data - Continued

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2010 and 2009 are as follows:

	At December 31	
	2010	2009
Upstream		
United States	**$ 26,319**	$ 25,478
International	**89,306**	81,209
Goodwill	**4,617**	4,618
Total Upstream	**120,242**	111,305
Downstream		
United States	**21,406**	20,317
International	**20,559**	19,618
Total Downstream	**41,965**	39,935
Total Segment Assets	**162,207**	151,240
All Other*		
United States	**11,125**	7,125
International	**11,437**	6,256
Total All Other	**22,562**	13,381
Total Assets United States	**58,850**	52,920
Total Assets International	**121,302**	107,083
Goodwill	**4,617**	4,618
Total Assets	**$ 184,769**	$ 164,621

* All Other assets consist primarily of worldwide cash, cash equivalents, time deposits and marketable securities, real estate, energy services, information systems, mining operations, power generation businesses, alternative fuels and technology companies, and assets of the corporate administrative functions.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2010, 2009 and 2008, are presented in the table at the right. Products are transferred between operating segments at internal product values that approximate market prices.

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

Other than the United States, no single country accounted for 10 percent or more of the company s total sales and other operating revenues in 2010, 2009 and 2008.

	Year ended December 31		
	2010	2009	2008
Upstream			
United States	**$ 10,316**	$ 9,225	$ 23,566
Intersegment	**13,839**	10,297	15,162
Total United States	**24,155**	19,522	38,728
International	**17,300**	13,463	19,531
Intersegment	**23,834**	18,477	24,205
Total International	**41,134**	31,940	43,736
Total Upstream	**65,289**	51,462	82,464
Downstream			
United States	**70,436**	58,056	87,759
Excise and similar taxes	**4,484**	4,573	4,748
Intersegment	**115**	98	242
Total United States	**75,035**	62,727	92,749
International	**90,922**	77,845	123,389
Excise and similar taxes	**4,107**	3,536	5,098
Intersegment	**93**	87	80
Total International	**95,122**	81,468	128,567
Total Downstream	**170,157**	144,195	221,316
All Other			
United States	**610**	665	815
Intersegment	**947**	964	917
Total United States	**1,557**	1,629	1,732
International	**23**	39	52
Intersegment	**39**	33	33
Total International	**62**	72	85
Total All Other	**1,619**	1,701	1,817
Segment Sales and Other Operating Revenues			
United States	**100,747**	83,878	133,209

International	**136,318**	113,480	172,388
Total Segment Sales and Other Operating Revenues	**237,065**	197,358	305,597
Elimination of intersegment sales	**(38,867)**	(29,956)	(40,639)
Total Sales and Other Operating Revenues	**$ 198,198**	$ 167,402	$ 264,958

Segment Income Taxes Segment income tax expense for the years 2010, 2009 and 2008 is as follows:

	Year ended December 31		
	2010	2009	2008
Upstream			
United States	**$ 2,285**	$ 1,251	$ 3,705
International	**10,480**	7,451	15,122
Total Upstream	**12,765**	8,702	18,827
Downstream			
United States	**680**	(83)	780
International	**462**	463	871
Total Downstream	**1,142**	380	1,651
All Other	**(988)**	(1,117)	(1,452)
Total Income Tax Expense	**$ 12,919**	$ 7,965	$ 19,026

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page FS-43. Information related to properties, plant and equipment by segment is contained in Note 13, on page FS-45.

Note 12

Investments and Advances

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

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2010	2009	**2010**	2009	2008
Upstream					
Tengizchevroil	**$ 5,789**	$ 5,938	**$ 3,398**	$ 2,216	$ 3,220
Petropiar/Hamaca	**973**	1,139	**262**	122	317
Caspian Pipeline Consortium	**974**	852	**124**	105	103
Petroboscan	**937**	832	**222**	171	244
Angola LNG Limited	**2,481**	1,853	**(21)**	(12)	(8)
Other	**1,922**	1,947	**319**	287	424
Total Upstream	**13,076**	12,561	**4,304**	2,889	4,300
Downstream					
GS Caltex Corporation	**2,496**	2,406	**158**	(191)	444
Chevron Phillips Chemical Company LLC	**2,419**	2,327	**704**	328	158
Star Petroleum Refining Company Ltd.	**947**	873	**122**	(4)	22
Caltex Australia Ltd.	**767**	740	**101**	11	250
Colonial Pipeline Company		514	**43**	51	32
Other	**602**	540	**151**	149	140
Total Downstream	**7,231**	7,400	**1,279**	344	1,046
All Other					
Other	**509**	507	**54**	83	20
Total equity method	**$ 20,816**	$ 20,468	**$ 5,637**	$ 3,316	$ 5,366
Other at or below cost	**704**	690			
Total investments and advances	**$ 21,520**	$ 21,158			
Total United States	**$ 3,769**	$ 4,195	**$ 846**	$ 511	$ 307
Total International	**$ 17,751**	$ 16,963	**$ 4,791**	$ 2,805	$ 5,059

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

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude oil fields in Kazakhstan over a 40-year period. At December 31, 2010, the company s carrying value of its investment in TCO was about
$190 higher than the amount of underlying equity in TCO s net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO s net assets. See Note 7, on page FS-36, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company formed in 2008 to operate the Hamaca heavy-oil production and upgrading project. The project, located in Venezuela s Orinoco Belt, has a 25-year contract term. Prior to the formation of Petropiar, Chevron had a 30 percent interest in the Hamaca project. At December 31, 2010, the company s carrying value of its investment in Petropiar was approximately $190 less than the amount of underlying equity in Petropiar s net assets. The difference represents the excess of Chevron s underlying equity in Petropiar s net assets over the net book value of the assets contributed to the venture.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, a variable interest entity, which provides the critical export route for crude oil from both TCO and Karachaganak. The company joined the consortium in 1997 and has investments and advances totaling $974 which includes long term loans of $1,046 at year-end 2010. The loans were provided to fund 30 percent of the pipeline construction. The company is not the primary beneficiary of the consortium because it does not direct activities of the consortium and only receives its proportionate share of the financial returns.

Petroboscan Chevron has a 39 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela until 2026. Chevron previously operated the field under an operating service agreement. At December 31, 2010, the company s carrying value of its investment in Petroboscan was approximately $250 higher than the amount of underlying equity in Petroboscan s net assets. The difference reflects the excess of the net book value of the assets contributed by Chevron over its underlying equity in Petroboscan s net assets.

Angola LNG Ltd. Chevron has a 36 percent interest in Angola LNG Ltd., which will process and liquefy natural gas produced in Angola for delivery to international markets.

Note 12 Investments and Advances - Continued

GS Caltex Corporation Chevron owns 50 percent of GS Caltex Corporation, a joint venture with GS Holdings. The joint venture imports, refines and markets petroleum products and petrochemicals, predominantly in South Korea.
Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC. The other half is owned by ConocoPhillips Corporation.
Star Petroleum Refining Company Ltd. Chevron has a 64 percent equity ownership interest in Star Petroleum Refining Company Ltd. (SPRC), which owns the Star Refinery in Thailand. PTT Public Company Limited owns the remaining 36 percent of SPRC.
Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Ltd. (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2010, the fair value of Chevron s share of CAL common stock was approximately $1,970.
Colonial Pipeline Company In October 2010, the company sold its 23.4 percent equity interest in the Colonial Pipeline Company.
Other Information Sales and other operating revenues on the Consolidated Statement of Income includes $13,672, $10,391 and $15,390 with affiliated companies for 2010, 2009 and 2008, respectively. Purchased crude oil and products includes $5,559, $4,631 and $6,850 with affiliated companies for 2010, 2009 and 2008, respectively.

Accounts and notes receivable on the Consolidated Balance Sheet includes $1,718 and $1,125 due from affiliated companies at December 31, 2010 and 2009, respectively. Accounts payable includes $377 and $345 due to affiliated companies at December 31, 2010 and 2009, respectively.

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron s total share, which includes Chevron loans to affiliates of $1,543, $2,422 and $2,820 at December 31, 2010, 2009 and 2008, respectively.

	Affiliates			Chevron Share		
Year ended December 31	**2010**	2009	2008	**2010**	2009	2008
Total revenues	**$ 107,505**	$ 81,995	$ 112,707	**$ 52,088**	$ 39,280	$ 54,055
Income before income tax expense	**18,468**	11,083	17,500	**7,966**	4,511	7,532
Net income attributable to affiliates	**12,831**	8,261	12,705	**5,683**	3,285	5,524
At December 31						
Current assets	**$ 30,335**	$ 27,111	$ 25,194	**$ 12,845**	$ 11,009	$ 10,804
Noncurrent assets	**57,491**	55,363	51,878	**21,401**	21,361	20,129
Current liabilities	**20,428**	17,450	17,727	**9,363**	7,833	7,474
Noncurrent liabilities	**19,749**	21,531	21,049	**4,459**	5,106	4,533
Total affiliates net equity	**$ 47,649**	$ 43,493	$ 38,296	**$ 20,424**	$ 19,431	$ 18,926

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Note 13

Properties, Plant and Equipment[1]

				At December 31						Year ended Decembe		
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expe		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2
ream												
d States	**$ 62,523**	$ 58,328	$ 54,878	**$ 23,277**	$ 22,273	$ 22,701	**$ 4,934**	$ 3,518	$ 5,395	**$ 4,078**	$ 3,992	$ 2
national	**110,578**	96,557	86,676	**64,388**	57,450	53,371	**14,381**	10,803	14,997	**7,448**	6,669	5
eam	**173,101**	154,885	141,554	**87,665**	79,723	76,072	**19,315**	14,321	20,392	**11,526**	10,661	8
nstream												
d States	**19,820**	18,962	17,397	**10,379**	10,032	8,908	**1,199**	1,874	2,061	**741**	666	
national	**9,697**	9,852	10,021	**3,948**	4,154	4,266	**361**	456	537	**451**	454	
nstream	**29,517**	28,814	27,418	**14,327**	14,186	13,174	**1,560**	2,330	2,598	**1,192**	1,120	1
ther[4]												
d States	**4,722**	4,569	4,310	**2,496**	2,548	2,523	**259**	354	598	**341**	325	
national	**27**	20	17	**16**	11	11	**11**	3	5	**4**	4	
All r	**4,749**	4,589	4,327	**2,512**	2,559	2,534	**270**	357	603	**345**	329	
United s	**87,065**	81,859	76,585	**36,152**	34,853	34,132	**6,392**	5,746	8,054	**5,160**	4,983	3
national	**120,302**	106,429	96,714	**68,352**	61,615	57,648	**14,753**	11,262	15,539	**7,903**	7,127	5
l	**$ 207,367**	$ 188,288	$ 173,299	**$ 104,504**	$ 96,468	$ 91,780	**$ 21,145**	$ 17,008	$ 23,593	**$ 13,063**	$ 12,110	$ 9

[1] Other than the United States and Nigeria, no other country accounted for 10 percent or more of the company s net properties, plant and equipment (PP&E) in 2010, 2009 and 2008. Nigeria had net

PP&E of $13,896, $12,463 and $10,730 for 2010, 2009 and 2008, respectively.

[2] Net of dry hole expense related to prior years expenditures of $82, $84 and $55 in 2010, 2009 and 2008, respectively.

[3] Depreciation expense includes accretion expense of $513, $463 and $430 in 2010, 2009 and 2008, respectively.

[4] Primarily mining operations, power generation businesses, real estate assets and management information systems.

Note 14

Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 19 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company s ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

Ecuador Chevron is a defendant in a civil lawsuit before the Superior Court of Nueva Loja in Lago Agrio, Ecuador, brought in May 2003 by plaintiffs who claim to be representatives of certain residents of an area where an oil production consortium formerly had operations. The lawsuit alleges damage to the environment from the oil exploration and production operations and seeks unspecified damages to fund environmental remediation and restoration of the alleged environmental harm, plus a health monitoring program. Until 1992, Texaco Petroleum Company (Texpet), a subsidiary of Texaco Inc., was a minority member of this consortium with Petroecuador, the

Ecuadorian state-owned oil company, as the majority partner; since 1990, the operations have been conducted solely by Petroecuador. At the conclusion of the consortium and following an independent third-party environmental audit of the concession area, Texpet entered into a formal agreement with the Republic of Ecuador and Petroecuador for Texpet to remediate specific sites assigned by the government in proportion to Texpet s ownership share of the consortium. Pursuant to that agreement, Texpet conducted a three-year remediation program at a cost of $40. After certifying that the sites were properly remediated, the government granted Texpet and all related corporate entities a full release from any and all environmental liability arising from the consortium operations.

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

In 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a

Note 14 Litigation - Continued

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

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

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador s obligations under the United States-Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador s obligations under the BIT. On February 9, 2011, the Permanent Court of Arbitration issued an Order for Interim Measures requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. Chevron expects to continue seeking permanent injunctive relief and monetary relief before the Tribunal.

Through a series of recent U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron has obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron is seeking relief that includes an award of damages and a declaration that any judgment against Chevron in the Lago Agrio litigation is the result of fraud and other unlawful conduct and is therefore unenforceable. On February 8, 2011, the Court issued a temporary restraining order prohibiting the Lago Agrio plaintiffs and persons acting in concert with them from taking any action in furtherance of recognition or enforcement of any judgment against Chevron in the Lago Agrio case until March 8, 2011. Chevron s motion for a preliminary injunction is presently before the Court.

On February 14, 2011, the Provincial Court in Lago Agrio rendered an adverse judgment in the case. The Provincial Court rejected Chevron s defenses to the extent the Court addressed them in its opinion. The judgment assesses approximately $8,600 in damages and about $900 for the plaintiffs representatives. It also assesses an additional amount of approximately $8,600 in punitive damages unless the company provides a public apology. Chevron continues to believe the Court s judgment is illegitimate and unenforceable in Ecuador, the United States and other countries. The company also believes the judgment is the product of fraud, and contrary to the legitimate scientific evidence. Chevron will appeal this decision in Ecuador. Chevron cannot predict the timing or ultimate outcome of the appeals process in Ecuador. Chevron will continue a vigorous defense of any imposition of liability. Because Chevron has no substantial assets in Ecuador, Chevron would expect enforcement actions as a result of this judgment to be brought in other jurisdictions. Chevron expects to contest any such actions.

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Note 14 Litigation - Continued

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

Note 15

Taxes

Income Taxes

	Year ended December 31		
	2010	2009	2008
Taxes on income			
U.S. Federal			
Current	**$ 1,501**	$ 128	$ 2,879
Deferred	**162**	(147)	274
State and local			
Current	**376**	216	528
Deferred	**20**	14	141
Total United States	**2,059**	211	3,822
International			
Current	**10,483**	7,154	15,021
Deferred	**377**	600	183
Total International	**10,860**	7,754	15,204
Total taxes on income	**$ 12,919**	$ 7,965	$ 19,026

In 2010, before-tax income for U.S. operations, including related corporate and other charges, was $6,528, compared with before-tax income of $1,310 and $10,765 in 2009 and 2008, respectively. For international operations, before-tax income was $25,527, $17,218 and $32,292 in 2010, 2009 and 2008, respectively. U.S. federal income tax expense was reduced by $162, $204 and $198 in 2010, 2009 and 2008, respectively, for business tax credits.

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

	Year ended December 31		
	2010	2009	2008
U.S. statutory federal income tax rate	**35.0%**	35.0%	35.0%
Effect of income taxes from inter-national operations at rates different from the U.S. statutory rate	**5.2**	10.4	10.1
State and local taxes on income, net of U.S. federal income tax benefit	**0.8**	0.9	1.0
Prior year tax adjustments	**(0.6)**	(0.3)	(0.1)

Tax credits	**(0.5)**	(1.1)	(0.5)
Effects of enacted changes in tax laws	**0.0**	0.1	(0.6)
Other	**0.4**	(2.0)	(0.7)
Effective tax rate	**40.3%**	43.0%	44.2%

The company s effective tax rate decreased from 43.0 percent in 2009 to 40.3 percent in 2010. The rate was lower in 2010 than in 2009 primarily due to international upstream impacts. A lower effective tax rate in international upstream in 2010 was primarily driven by 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.

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

	At December 31	
	2010	2009
Deferred tax liabilities		
Properties, plant and equipment	**$ 19,855**	$ 18,545
Investments and other	**2,401**	2,350
Total deferred tax liabilities	**22,256**	20,895
Deferred tax assets		
Foreign tax credits	**(6,669)**	(5,387)
Abandonment/environmental reserves	**(5,004)**	(4,424)
Employee benefits	**(3,627)**	(3,499)
Deferred credits	**(2,176)**	(3,469)
Tax loss carryforwards	**(882)**	(819)
Other accrued liabilities	**(486)**	(553)
Inventory	**(483)**	(431)
Miscellaneous	**(1,676)**	(1,681)
Total deferred tax assets	**(21,003)**	(20,263)
Deferred tax assets valuation allowance	**9,185**	7,921
Total deferred taxes, net	**$ 10,438**	$ 8,553

Deferred tax liabilities at the end of 2010 increased by almost $1,400 from year-end 2009. The increase was primarily related to increased temporary differences for property, plant and equipment.

Deferred tax assets increased by approximately $700 in 2010. Increases primarily related to additional foreign tax credits arising from earnings in high-tax-rate international jurisdictions (which were substantially offset by valuation allowances) and to increased temporary differences for asset retirement obligations, environmental reserves and employee benefits. These effects were partially offset by reductions in deferred credits resulting primarily from the usage of tax benefits in international tax jurisdictions.

The overall valuation allowance relates to deferred tax assets for foreign tax credit carryforwards, tax loss carryforwards and temporary differences. It reduces the deferred tax assets to amounts that are, in management s assessment, more likely than not to be realized. Tax loss carryforwards

Note 15 Taxes - Continued

exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2011 through 2036. Foreign tax credit carryforwards of $6,669 will expire between 2011 and 2020.

At December 31, 2010 and 2009, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2010	2009
Prepaid expenses and other current assets	**$ (1,624)**	$ (1,825)
Deferred charges and other assets	**(851)**	(1,268)
Federal and other taxes on income	**216**	125
Noncurrent deferred income taxes	**12,697**	11,521
Total deferred income taxes, net	**$ 10,438**	$ 8,553

Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled $21,347 at December 31, 2010. This amount represents earnings reinvested as part of the company s ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of earnings that are intended to be reinvested indefinitely. At the end of 2010, deferred income taxes were recorded for the undistributed earnings of certain international operations for which the company no longer intends to indefinitely reinvest the earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

Uncertain Income Tax Positions Under accounting standards for uncertainty in income taxes (ASC 740-10), a company recognizes a tax benefit in the financial statements for an uncertain tax position only if management s assessment is that the position is more likely than not (i.e., a likelihood greater than 50 percent) to be allowed by the tax jurisdiction based solely on the technical merits of the position. The term tax position in the accounting standards for income taxes (ASC 740-10-20) refers to a position in a previously filed tax return or a position expected to be taken in a future tax return that is reflected in measuring current or deferred income tax assets and liabilities for interim or annual periods.

The following table indicates the changes to the company s unrecognized tax benefits for the years ended December 31, 2010, 2009 and 2008. The term unrecognized tax benefits in the accounting standards for income taxes (ASC 740-10-20) refers to the differences between a tax position taken or expected to be taken in a tax return and the benefit measured and recognized in the financial statements. Interest and penalties are not included.

	2010	2009	2008
Balance at January 1	**$ 3,195**	$ 2,696	$ 2,199
Foreign currency effects	**17**	(1)	(1)
Additions based on tax positions taken in current year	**334**	459	522
Reductions based on tax positions taken in current year			(17)
Additions/reductions resulting from current-year asset acquisitions/sales			175

Additions for tax positions taken in prior years	**270**	533	337
Reductions for tax positions taken in prior years	**(165)**	(182)	(246)
Settlements with taxing authorities in current year	**(136)**	(300)	(215)
Reductions as a result of a lapse of the applicable statute of limitations	**(8)**	(10)	(58)
Balance at December 31	**$ 3,507**	$ 3,195	$ 2,696

Approximately 80 percent of the $3,507 of unrecognized tax benefits at December 31, 2010, would have an impact on the effective tax rate if subsequently recognized. Certain of these unrecognized tax benefits relate to tax carryforwards that may require a full valuation allowance at the time of any such recognition.

Tax positions for Chevron and its subsidiaries and affiliates are subject to income tax audits by many tax jurisdictions throughout the world. For the company s major tax jurisdictions, examinations of tax returns for certain prior tax years had not been completed as of December 31, 2010. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States 2005, Nigeria 1994, Angola 2001 and Saudi Arabia 2003.

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

On the Consolidated Statement of Income, the company reports interest and penalties related to liabilities for uncertain tax positions as Income tax expense. As of December 31, 2010, accruals of $225 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $232 as of year-end 2009. Income tax expense (benefit) associated with interest and penalties was $40, $(20) and $79 in 2010, 2009 and 2008, respectively.

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Note 15 Taxes - Continued

Taxes Other Than on Income

	Year ended December 31		
	2010	2009	2008
United States			
Excise and similar taxes on products and merchandise	**$ 4,484**	$ 4,573	$ 4,748
Import duties and other levies		(4)	1
Property and other miscellaneous taxes	**567**	584	588
Payroll taxes	**219**	223	204
Taxes on production	**271**	135	431
Total United States	**5,541**	5,511	5,972
International			
Excise and similar taxes on products and merchandise	**4,107**	3,536	5,098
Import duties and other levies	**6,183**	6,550	8,368
Property and other miscellaneous taxes	**2,000**	1,740	1,557
Payroll taxes	**133**	134	106
Taxes on production	**227**	120	202
Total International	**12,650**	12,080	15,331
Total taxes other than on income	**$ 18,191**	$ 17,591	$ 21,303

Note 16

Short-Term Debt

	At December 31	
	2010	2009
Commercial paper*	**$ 2,471**	$ 2,499
Notes payable to banks and others with originating terms of one year or less	**43**	213
Current maturities of long-term debt	**33**	66
Current maturities of long-term capital leases	**81**	*76*
Redeemable long-term obligations		
Long-term debt	**2,943**	1,702
Capital leases	**16**	18
Subtotal	**5,587**	4,574
Reclassified to long-term debt	**(5,400)**	(4,190)

Total short-term debt	**$ 187**	$ 384

* Weighted-average interest rates at December 31, 2010 and 2009, were 0.16 percent and 0.08 percent, respectively.

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

In 2010, $1,250 of tax-exempt bonds related to projects at the Pascagoula and El Segundo refineries were issued.

The company periodically enters into interest rate swaps on a portion of its short-term debt. At December 31, 2010, the company had no interest rate swaps on short-term debt.

At December 31, 2010, the company had $6,000 in committed credit facilities with various major banks, expiring in May 2013, that 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, 2010.

At December 31, 2010 and 2009, the company classified $5,400 and $4,190, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital within one year, as the company has both the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Note 17

Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2010, was $11,003. The company s long-term debt outstanding at year-end 2010 and 2009 was as follows:

	At December 31	
	2010	2009
3.95% notes due 2014	**$ 1,998**	$ 1,997
3.45% notes due 2012	**1,500**	1,500
4.95% notes due 2019	**1,500**	1,500
8.625% debentures due 2032	**147**	147
8.625% debentures due 2031	**107**	107
7.5% debentures due 2043	**83**	83
8% debentures due 2032	**74**	74
7.327% amortizing notes due 2014[1]	**72**	109
9.75% debentures due 2020	**54**	56
8.875% debentures due 2021	**40**	40
8.625% debentures due 2010		30
Medium-term notes, maturing from 2021 to 2038 (5.97%)[2]	**38**	38
Fixed interest rate notes, maturing 2011 (9.378%)[2]	**19**	19
Other foreign currency obligations		
Other long-term debt (5.66%)[2]	**4**	5

Total including debt due within one year	**5,636**	5,705
Debt due within one year	**(33)**	(66)
Reclassified from short-term debt	**5,400**	4,190
Total long-term debt	**$ 11,003**	$ 9,829

[1] Guarantee of ESOP debt.

[2] Weighted-average interest rate at December 31, 2010.

Long-term debt of $5,636 matures as follows: 2011 $33; 2012 $1,520; 2013 $20; 2014 $2,020; 2015 $0; and after 2015 $2,043.

In 2010, $30 of bonds matured. In 2009, $5,000 of public bonds was issued, and $400 of Texaco Capital Inc. bonds matured.

See Note 9, beginning on page FS-37, for information concerning the fair value of the company s long-term debt.

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Note 18

New Accounting Standards

Transfers and Servicing (ASC 860), Accounting for Transfers of Financial Assets (ASU 2009-16) The FASB issued ASU 2009-16 in December 2009. This standard became effective for the company on January 1, 2010. ASU 2009-16 changes how companies account for transfers of financial assets and eliminates the concept of qualifying special-purpose entities. Adoption of the guidance did not have an effect on the company s results of operations, financial position or liquidity.

Consolidation (ASC 810), Improvements to Financial Reporting by Enterprises Involved With Variable Interest Entities (ASU 2009-17) The FASB issued ASU 2009-17 in December 2009. This standard became effective for the company January 1, 2010. ASU 2009-17 requires the enterprise to qualitatively assess if it is the primary beneficiary of a variable-interest entity (VIE), and if so, the VIE must be consolidated. Adoption of the standard did not have an impact on the company s results of operations, financial position or liquidity.

Receivables (ASC 310), Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses (ASU 2010-20) In July 2010, the FASB issued ASU 2010-20, which became effective with the company s reporting at December 31, 2010. This standard amends and expands disclosure requirements about the credit quality of financing receivables and the related allowance for credit losses. As a result of these amendments, companies are required to disaggregate, by portfolio segment or class of financing receivable, certain existing disclosures and provide certain new disclosures about financing receivables and related allowance for credit losses. Adoption of the standard did not change the company s existing disclosures.

Note 19

Accounting for Suspended Exploratory Wells

Accounting standards for the costs of exploratory wells (ASC 932) provide that exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. (Note that an entity is not required to complete the exploratory or exploratory-type stratigraphic well as a producing well.) The accounting standards provide a number of indicators that can assist an entity in demonstrating that sufficient progress is being made in assessing the reserves and economic viability of the project. The following table indicates the changes to the company s suspended exploratory well costs for the three years ended December 31, 2010:

	2010	2009	2008
Beginning balance at January 1	**$ 2,435**	$ 2,118	$ 1,660
Additions to capitalized exploratory well costs pending the determination of proved reserves	**482**	663	643
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(129)**	(174)	(49)
Capitalized exploratory well costs charged to expense	**(70)**	(172)	(136)
Ending balance at December 31	**$ 2,718**	$ 2,435	$ 2,118

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

	At December 31		
	2010	2009	2008
Exploratory well costs capitalized for a period of one year or less	**$ 419**	$ 564	$ 559
Exploratory well costs capitalized for a period greater than one year	**2,299**	1,871	1,559
Balance at December 31	**$ 2,718**	$ 2,435	$ 2,118
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**53**	46	50

* Certain projects have multiple wells or fields or both.

Of the $2,299 of exploratory well costs capitalized for more than one year at December 31, 2010, $982 (26 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $1,317 balance is related to 27 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the $1,317 referenced above had the following activities associated with assessing the reserves and the projects economic viability: (a) $501 (three projects) project sanction approved and construction is in progress, with initial recognition of proved reserves expected upon reaching economic producibility per SEC guidelines; (b) $263 (six projects) development alternatives under review; (c) $178 (three projects) in process of entering contracts for front-end engineering and design; (d) $154 (three projects) progression of development concept selection and unitization agreement; (e) $109 (five projects) undergoing front-end engineering

Note 19 Accounting for Suspended Exploratory Wells - Continued
and design with final investment decision expected in 2011; (f) $73 (two projects) development concept under review by government; $39 miscellaneous activities for five projects with smaller amounts suspended. While progress was being made on all 53 projects, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations connected with the projects. The majority of these decisions are expected to occur in the next three years.

The $2,299 of suspended well costs capitalized for a period greater than one year as of December 31, 2010, represents 176 exploratory wells in 53 projects. The tables below contain the aging of these costs on a well and project basis:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1992	$ 8	3
1997 1999	27	6
2000 2004	442	54
2005 2009	1,822	113
Total	$ 2,299	176

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
1992	$ 8	1
1999	8	1
2003 2005	340	9
2006 2010	1,943	42
Total	$ 2,299	53

Note 20
Stock Options and Other Share-Based Compensation
Compensation expense for stock options for 2010, 2009 and 2008 was $229 ($149 after tax), $182 ($119 after tax) and $168 ($109 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was $194 ($126 after tax), $170 ($110 after tax) and $132 ($86 after tax) for 2010, 2009 and 2008, respectively. No significant stock-based compensation cost was capitalized at December 31, 2010 and 2009.

Cash received in payment for option exercises under all share-based payment arrangements for 2010, 2009 and 2008 was $385, $147 and $404, respectively. Actual tax benefits realized for the tax deductions from option exercises were $66, $25 and $103 for 2010, 2009 and 2008, respectively.

Cash paid to settle performance units and stock appreciation rights was $140, $89 and $136 for 2010, 2009 and 2008, respectively.

Chevron Long-Term Incentive Plan (LTIP) Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and nonstock grants. From April 2004 through January 2014, no more than 160 million shares may be issued under the LTIP, and no more than 64 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient. For the major types of awards outstanding as of December 31, 2010, the contractual terms vary between three years for the performance units and 10 years for the stock options and stock appreciation rights.

Texaco Stock Incentive Plan (Texaco SIP) On the closing of the acquisition of Texaco in October 2001, outstanding options granted under the Texaco SIP were converted to Chevron options. These options, which have 10-year contractual lives extending into 2011, retained a provision for being restored. This provision enables a participant who exercises a stock option to receive new options equal to the number of shares exchanged or who has shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant, and the exercise price is the market value of the common stock on the day the restored option is granted. Beginning in 2007, restored options were issued under the LTIP. No further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) When Chevron acquired Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights. These awards retained the same provisions as the original Unocal Plans. Unexercised awards began expiring in early 2010 and will continue to expire through early 2015.

Note 20 Stock Options and Other Share-Based Compensation - Continued

The fair market values of stock options and stock appreciation rights granted in 2010, 2009 and 2008 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2010	2009	2008
Stock Options			
Expected term in years[1]	**6.1**	6.0	6.1
Volatility[2]	**30.8%**	30.2%	22.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**2.9%**	2.1%	3.0%
Dividend yield	**3.9%**	3.2%	2.7%
Weighted-average fair value per option granted	**$ 16.28**	$ 15.36	$ 15.97
Restored Options			
Expected term in years[1]	**1.2**	1.2	1.2
Volatility[2]	**38.9%**	45.0%	23.1%
Risk-free interest rate based on zero coupon U.S. treasury note	**0.6%**	1.1%	1.9%
Dividend yield	**3.8%**	3.5%	2.7%
Weighted-average fair value per option granted	**$ 12.91**	$ 12.38	$ 10.01

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

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

A summary of option activity during 2010 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	69,463	$ 63.70		
Granted	15,454	$ 73.70		
Exercised	(8,133)	$ 49.82		
Restored	27	$ 78.41		
Forfeited	(1,959)	$ 73.34		
Outstanding at December 31, 2010	74,852	$ 67.04	6.4 yrs	$ 1,813

Exercisable at December 31, 2010	48,174	$ 63.29	5.2 yrs	$ 1,348

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2010, 2009 and 2008 was $259, $91 and $433, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2010, there was $242 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 1.7 years.

At January 1, 2010, the number of LTIP performance units outstanding was equivalent to 2,679,108 shares. During 2010, 1,104,000 units were granted, 881,759 units vested with cash proceeds distributed to recipients and 173,475 units were forfeited. At December 31, 2010, units outstanding were 2,727,874, and the fair value of the liability recorded for these instruments was $266. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 1.6 million equivalent shares as of December 31, 2010. A liability of $40 was recorded for these awards.

In March 2009, Chevron granted all eligible LTIP employees restricted stock units in lieu of an annual cash bonus. A total of 453,965 units were granted at $69.70 per unit at the time of the grant. The expense associated with these special restricted stock units was recognized in 2009. All of the special restricted stock units were distributed in November 2010.

Note 21

Employee Benefit Plans

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

The company also sponsors other postretirement (OPEB) plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and retirees share the costs. Medical coverage for Medicare-eligible retirees in the company s main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the company contribution for retiree medical coverage is limited to no more than 4 percent each year. Certain life insurance benefits are paid by the company.

Under accounting standards for postretirement benefits (ASC 715), the company recognizes the overfunded or underfunded status of each of its defined benefit pension and OPEB plans as an asset or liability on the Consolidated Balance Sheet.

The funded status of the company s pension and other postretirement benefit plans for 2010 and 2009 is on the following page:

Note 21 Employee Benefit Plans - Continued

	Pension Benefits				Other Benefits	
	2010		2009			
	U.S.	Int l.	U.S.	Int l.	**2010**	2009
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 9,664**	**$ 4,715**	$ 8,127	$ 3,891	**$ 3,065**	$ 2,931
Service cost	**337**	**153**	266	128	**39**	43
Interest cost	**486**	**307**	481	292	**175**	180
Plan participants contributions		**7**		7	**147**	145
Plan amendments			1	10	**12**	20
Curtailments						(5)
Actuarial loss (gain)	**568**	**200**	1,391	299	**486**	56
Foreign currency exchange rate changes		**(17)**		333	**11**	27
Benefits paid	**(784)**	**(295)**	(602)	(245)	**(330)**	(332)
Benefit obligation at December 31	**10,271**	**5,070**	9,664	4,715	**3,605**	3,065
Change in Plan Assets						
Fair value of plan assets at January 1	**7,304**	**3,235**	5,448	2,600		
Actual return on plan assets	**867**	**361**	964	402		
Foreign currency exchange rate changes		**(63)**		226		
Employer contributions	**1,192**	**258**	1,494	245	**183**	187
Plan participants contributions		**7**		7	**147**	145
Benefits paid	**(784)**	**(295)**	(602)	(245)	**(330)**	(332)
Fair value of plan assets at December 31	**8,579**	**3,503**	7,304	3,235		
Funded Status at December 31	**$ (1,692)**	**$ (1,567)**	$ (2,360)	$ (1,480)	**$ (3,605)**	$ (3,065)

Amounts recognized on the Consolidated Balance Sheet for the company s pension and other postretirement benefit plans at December 31, 2010 and 2009, include:

	Pension Benefits				Other Benefits	
	2010		2009			
	U.S.	Int l.	U.S.	Int l.	**2010**	2009
Deferred charges and other assets	**$ 7**	**$ 77**	$ 6	$ 37	**$**	$
Accrued liabilities	**(134)**	**(71)**	(66)	(67)	**(225)**	(208)

Reserves for employee benefit plans	**(1,565)**	**(1,573)**	(2,300)	(1,450)	**(3,380)**	(2,857)
Net amount recognized at December 31	**$ (1,692)**	**$ (1,567)**	$ (2,360)	$ (1,480)	**$ (3,605)**	$ (3,065)

Amounts recognized on a before-tax basis in Accumulated other comprehensive loss for the company s pension and OPEB plans were $6,749 and $6,454 at the end of 2010 and 2009, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2010		2009			
	U.S.	Int l.	U.S.	Int l.	**2010**	2009
Net actuarial loss	**$ 3,919**	**$ 1,903**	$ 4,181	$ 1,889	**$ 935**	$ 465
Prior service (credit) costs	**(52)**	**179**	(60)	201	**(135)**	(222)
Total recognized at December 31	**$ 3,867**	**$ 2,082**	$ 4,121	$ 2,090	**$ 800**	$ 243

The accumulated benefit obligations for all U.S. and international pension plans were $9,535 and $4,161, respectively, at December 31, 2010, and $8,707 and $4,029, respectively, at December 31, 2009.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2010 and 2009, was:

	Pension Benefits			
	2010		2009	
	U.S.	Int l.	U.S.	Int l.
Projected benefit obligations	**$ 10,265**	**$ 3,668**	$ 9,658	$ 3,550
Accumulated benefit obligations	**9,528**	**3,113**	8,702	3,102
Fair value of plan assets	**8,566**	**2,190**	7,292	2,116

Notes to the Consolidated Financial Statements
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Note 21 Employee Benefit Plans - Continued

The components of net periodic benefit cost and amounts recognized in other comprehensive income for 2010, 2009 and 2008 are shown in the table below:

	Pension Benefits						Other Benefits		
	2010		2009		2008				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2010**	2009	2008
Net Periodic Benefit Cost									
Service cost	**$ 337**	**$ 153**	$ 266	$ 128	$ 250	$ 132	**$ 39**	$ 43	$ 44
Interest cost	**486**	**307**	481	292	499	292	**175**	180	178
Expected return on plan assets	**(538)**	**(241)**	(395)	(203)	(593)	(273)			
Amortization of prior service (credits) costs	**(8)**	**22**	(7)	23	(7)	24	**(75)**	(81)	(81)
Recognized actuarial losses	**318**	**98**	298	108	60	77	**27**	27	38
Settlement losses	**186**	**6**	141	1	306	2			
Curtailment losses								(5)	
Special termination benefit recognition						1			
Total net periodic benefit cost	**781**	**345**	784	349	515	255	**166**	164	179
Changes Recognized in Other Comprehensive Income									
Net actuarial loss (gain) during period	**242**	**118**	823	194	2,624	646	**497**	82	(42)
Amortization of actuarial loss	**(504)**	**(104)**	(439)	(109)	(366)	(79)	**(27)**	(27)	(38)
Prior service cost during period			1	13		32	**12**	20	
Amortization of prior service credits (costs)	**8**	**(22)**	7	(23)	7	(24)	**75**	81	81
Total changes recognized in other comprehensive income	**(254)**	**(8)**	392	75	2,265	575	**557**	156	1
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 527**	**$ 337**	$ 1,176	$ 424	$ 2,780	$ 830	**$ 723**	$ 320	$ 180

Net actuarial losses recorded in Accumulated other comprehensive loss at December 31, 2010, for the company s U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 10, 12 and 10 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2011, the company estimates actuarial losses of $314, $114 and $64 will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and OPEB plans, respec-
tively. In addition, the company estimates an additional $250 will be recognized from Accumulated other comprehensive loss during 2011 related to lump-sum settlement costs from U.S. pension plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded in Accumulated other comprehensive loss at December 31, 2010, was approximately seven and 11 years for U.S. and international pension plans, respectively, and 12 years for other postretirement benefit plans. During 2011, the company estimates prior service (credits) costs of $(8), $27 and $(72) will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and OPEB plans, respectively.

Note 21 Employee Benefit Plans - Continued

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

	Pension Benefits								
	2010		2009		2008		Other Benefits		
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2010**	2009	2008
Assumptions used to determine benefit obligations:									
Discount rate	**4.8%**	**6.5%**	5.3%	6.8%	6.3%	7.5%	**5.2%**	5.9%	6.3%
Rate of compensation increase	**4.5%**	**6.7%**	4.5%	6.3%	4.5%	6.8%	**N/A**	N/A	4.0%
Assumptions used to determine net periodic benefit cost:									
Discount rate	**5.3%**	**6.8%**	6.3%	7.5%	6.3%	6.7%	**5.9%**	6.3%	6.3%
Expected return on plan assets	**7.8%**	**7.8%**	7.8%	7.5%	7.8%	7.4%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**6.3%**	4.5%	6.8%	4.5%	6.4%	**N/A**	N/A	4.5%

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

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 70 percent of the company s pension plan assets. At December 31, 2010, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

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

Discount Rate The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2010, the company selected a 4.8 percent discount rate for the U.S. pension plan and 5.0 percent for the U.S. postretirement benefit plan. This rate was based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2010. The discount rates at the end of 2009 were 5.3 percent and 5.8 percent for the U.S. pension plan and the U.S. OPEB plan, respectively. The discount rate at the end of
2008 was 6.3 percent for both the U.S. pension plan and the U.S. OPEB plan.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2010, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 8 percent in 2011 and gradually decline to 5 percent for 2018 and beyond. For this measurement at December 31, 2009, the assumed health care cost-trend rates started with 7 percent in 2010 and gradually declined to 5 percent for 2018 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company s medical contributions for the primary U.S. plan.

A one-percentage-point change in the assumed health care cost-trend rates would have the following effects:

	1 Percent Increase	1 Percent Decrease
Effect on total service and interest cost components	$ 11	$ (9)
Effect on postretirement benefit obligation	$ 146	$ (125)

Plan Assets and Investment Strategy The accounting standards for defined benefit pension and OPEB plans (ASC 715) provide users of financial statements with an understanding of: how investment allocation decisions are made; the major classes of plan assets; the inputs and valuation techniques used to measure the fair value of plan assets; the effect of fair value measurements using unobservable inputs on changes in plan assets for the period; and significant concentrations of risk within plan assets.

The fair value hierarchy of inputs the company uses to value the pension assets is divided into three levels:

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Notes to the Consolidated Financial Statements
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Note 21 Employee Benefit Plans - Continued

Level 1: Fair values of these assets are measured using unadjusted quoted prices for the assets or the prices of identical assets in active markets that the plans have the ability to access.

Level 2: Fair values of these assets are measured based on quoted prices for similar assets in active markets; quoted prices for identical or similar assets in inactive markets; inputs other than quoted prices that are observable for the asset; and inputs that are derived principally from or corroborated by observable market data by correlation or other means. If the
asset has a contractual term, the Level 2 input is observable for substantially the full term of the asset. The fair values for Level 2 assets are generally obtained from third-party broker quotes, independent pricing services and exchanges.

Level 3: Inputs to the fair value measurement are unobservable for these assets. Valuation may be performed using a financial model with estimated inputs entered into the model.

The fair value measurements of the company s pension plans for 2010 are below:

	U.S.				Int l			
	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
At December 31, 2010								
Equities								
U.S.[1]	**$ 2,121**	**$ 2,121**	**$**	**$**	**$ 465**	**$ 465**	**$**	**$**
International	**1,405**	**1,405**			**721**	**721**		
Collective Trusts/Mutual Funds[2]	**2,068**	**5**	**2,063**		**578**	**80**	**498**	
Fixed Income								
Government	**659**	**19**	**640**		**568**	**38**	**530**	
Corporate	**314**		**314**		**351**	**24**	**299**	**28**
Mortgage-Backed Securities	**82**		**82**		**2**			**2**
Other Asset Backed	**74**		**74**		**16**		**16**	
Collective Trusts/Mutual Funds[2]	**1,064**		**1,064**		**332**	**19**	**313**	
Mixed Funds[3]	**9**	**9**			**105**	**16**	**89**	
Real Estate[4]	**596**			**596**	**142**			**142**
Cash and Cash Equivalents	**213**	**213**			**217**	**217**		
Other[5]	**(26)**	**(87)**	**8**	**53**	**6**	**(5)**	**9**	**2**
Total at December 31, 2010	**$ 8,579**	**$ 3,685**	**$ 4,245**	**$ 649**	**$ 3,503**	**$ 1,575**	**$ 1,754**	**$ 174**
At December 31, 2009								
Equities								

U.S.[1]	$ 2,115	$ 2,115	$	$	$ 370	$ 370	$	$
International	977	977			492	492		
Collective Trusts/Mutual Funds[2,6]	1,264	3	1,261		786	91	695	
Fixed Income								
Government	713	149	564		506	54	452	
Corporate	430		430		371	17	336	18
Mortgage-Backed Securities	149		149		2			2
Other Asset Backed	90		90		19		19	
Collective Trusts/Mutual Funds[2]	326		326		230	14	216	
Mixed Funds[3,6]	8	8			105	17	88	
Real Estate[4]	479			479	131			131
Cash and Cash Equivalents	743	743			207	207		
Other[5]	10	(57)	16	51	16	(3)	18	1
Total at December 31, 2009	$ 7,304	$ 3,938	$ 2,836	$ 530	$ 3,235	$ 1,259	$ 1,824	$ 152

[1] U.S. equities include investments in the company s common stock in the amount of $38 at December 31, 2010 and $29 at December 31, 2009.

[2] Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is partially based on the restriction that advance notification of redemptions,

typically two business days, is required.

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

[4] The year-end valuations of the U.S. real estate assets are based on internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.

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

[6] Certain amounts have been reclassified to conform to their 2010 presentation.

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Note 21 Employee Benefit Plans - Continued

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

	U.S. Equities	Corporate	Fixed Income Mortgage-Backed Securities	Real Estate	Other	Total
Total at December 31, 2008	$ 1	$ 23	$ 2	$ 763	$ 52	$ 841
Actual Return on Plan Assets:						
Assets held at the reporting date	(1)	2		(178)		(177)
Assets sold during the period		5		8		13
Purchases, Sales and Settlements		(12)		17		5
Transfers in and/or out of Level 3						
Total at December 31, 2009	$	$ 18	$ 2	$ 610	$ 52	$ 682
Actual Return on Plan Assets:						
Assets held at the reporting date		**3**		**34**	**1**	**38**
Assets sold during the period				**1**		**1**
Purchases, Sales and Settlements		**7**		**93**	**2**	**102**
Transfers in and/or out of Level 3						
Total at December 31, 2010	**$**	**$ 28**	**$ 2**	**$ 738**	**$ 55**	**$ 823**

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

The company s U.S. and U.K. pension plans comprise 86 percent of the total pension assets. Both the U.S. and U.K. plans have an Investment Committee that regularly meets during the year to review the asset holdings and their returns. To assess the plans investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has established the following approved asset allocation ranges: Equities 40-70 percent, Fixed Income and Cash 20-65 percent, Real Estate 0-15 percent, and Other 0-5 percent. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines, which are reviewed regularly: Equities 60-80 percent and Fixed Income and Cash 20-40 percent. The other significant international pension plans also have established maximum and minimum asset allocation ranges that vary by plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset class risk. There are no significant concentrations of risk in plan assets due to the diversification of investment classes.

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2010, the company contributed $1,192 and $258 to its U.S. and international pension plans, respectively. In 2011, the company expects contributions to be approximately $650 and

$300 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately $225 in 2011, as compared with $183 paid in 2010.

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

	Pension Benefits		Other
	U.S.	Int l.	Benefits
2011	$ 994	$ 247	$ 225
2012	$ 926	$ 298	$ 230
2013	$ 924	$ 300	$ 238
2014	$ 934	$ 320	$ 246
2015	$ 937	$ 346	$ 253
2016 2020	$ 4,687	$ 2,095	$ 1,345

Note 21 Employee Benefit Plans - Continued

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP).

Charges to expense for the ESIP represent the company s contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is described in the section that follows. Total company matching contributions to employee accounts within the ESIP were $253, $257, and $231 in 2010, 2009 and 2008, respectively. This cost was reduced by the value of shares released from the LESOP totaling $97, $184 and $40 in 2010, 2009 and 2008, respectively. The remaining amounts, totaling $156, $73 and $191 in 2010, 2009 and 2008, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron ESIP is an employee stock ownership plan (ESOP). In 1989, Chevron established a LESOP as a constituent part of the ESOP. The LESOP provides partial prefunding of the company s future commitments to the ESIP.

As permitted by accounting standards for share-based compensation (ASC 718), the debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as Deferred compensation and benefit plan trust on the Consolidated Balance Sheet and the Consolidated Statement of Equity.

The company reports compensation expense equal to LESOP debt principal repayments less dividends received and used by the LESOP for debt service. Interest accrued on LESOP debt is recorded as interest expense. Dividends paid on LESOP shares are reflected as a reduction of retained earnings. All LESOP shares are considered outstanding for earnings-per-share computations.

Total credits to expense for the LESOP were $1, $3 and $1 in 2010, 2009 and 2008, respectively. The net credit for the respective years was composed of credits to compensation expense of $6, $15 and $15 and charges to interest expense for LESOP debt of $5, $12 and $14.

Of the dividends paid on the LESOP shares, $46, $110 and $35 were used in 2010, 2009 and 2008, respectively, to service LESOP debt. No contributions were required in 2010, 2009 or 2008, as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Shares held in the LESOP are released and allocated to the accounts of plan participants based on debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. LESOP shares as of December 31, 2010 and 2009, were as follows:

Thousands	**2010**	2009
Allocated shares	**20,718**	21,211
Unallocated shares	**2,374**	3,636
Total LESOP shares	**23,092**	24,847

Benefit Plan Trusts Prior to its acquisition by Chevron, Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2010, the trust contained 14.2 million shares of Chevron treasury stock. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The company intends to continue to pay its obligations under the benefit plans. The trustee will vote the shares held in the trust as instructed by the trust s beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Prior to its acquisition by Chevron, Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2010 and 2009, trust assets of $57 were invested primarily in interest-earning accounts.

Employee Incentive Plans The Chevron Incentive Plan is an annual cash bonus plan for eligible employees that links awards to corporate, unit and individual performance in the prior year. Charges to expense for cash bonuses were $766, $561 and $757 in 2010, 2009 and 2008, respectively. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 20, on page FS-51.

Note 22

Equity

Retained earnings at December 31, 2010 and 2009, included approximately $9,159 and $8,122, respectively, for the company s share of undistributed earnings of equity affiliates.

At December 31, 2010, about 81 million shares of Chevron s common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP).

Note 22 Equity - Continued

In addition, approximately 280,000 shares remain available for issuance from the 800,000 shares of the company s common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan.

Note 23

Restructuring and Reorganization

In the first quarter 2010, the company announced employee reduction programs related to the restructuring and reorganization of its downstream businesses and corporate staffs. The initial estimate included approximately 3,200 employees in Downstream and 600 employees from corporate staffs that were expected to be terminated under the programs. Due to redeployment efforts within the company, total employee terminations under the programs are expected to be reduced from approximately 3,800 employees to approximately 3,200 employees. About 1,500 of the affected employees are located in the United States. About 1,500 employees have been terminated to date, and the programs are expected to be completed by the end of 2011.

A before-tax charge of $244 ($175 after tax) was recorded in first quarter 2010, with $191 reported as Operating expenses and $53 as Selling, general and administrative expenses on the Consolidated Statement of Income. Due to the reduction in terminations resulting from reassignments within the company, an adjustment to total charges was made in fourth quarter 2010, which effectively reduced the total before-tax charge from $244 to $234 ($167 after tax). The accrued liability is classified as current on the Consolidated Balance Sheet. Approximately $71 ($45 after tax) is associated with terminations in U.S. Downstream, $119 ($92 after tax) in International Downstream and $44 ($30 after tax) in All Other.

During the last nine months of 2010, the company made payments of $96 associated with these liabilities. The majority of the payments were in Downstream.

		Amounts Before Tax
Balance at January 1, 2010	$	
Accruals		244
Adjustments		(10)
Payments		(96)
Balance at December 31, 2010	$	138

Note 24

Other Contingencies and Commitments

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 15, beginning on page FS-47, for a discussion of the periods for which tax returns have been audited for the company s major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

Guarantees The company s guarantee of approximately $600 is associated with certain payments under a terminal use agreement entered into by a company affiliate. The terminal is expected to be operational by 2012. Over the approximate 16-year term of the guarantee, the maximum guarantee amount will be reduced over time as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of any amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company s interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300. Through the end of 2010, the company paid $48 under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco s ownership interest in the joint ventures. In general, the environmental conditions or events

Note 24 Other Contingencies and Commitments - Continued

that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described in the preceding paragraph are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any applicable incident.

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

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company s business. The aggregate approximate amounts of required payments under these various commitments are: 2011 $17,200; 2012 $4,100; 2013 $3,500; 2014 $3,100; 2015 $3,000; 2016 and after $7,700. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $6,500 in 2010, $8,100 in 2009 and $5,100 in 2008.

Environmental The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company s liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company s competitive position relative to other U.S. or international petroleum or chemical companies.

Chevron s environmental reserve as of December 31, 2010, was $1,507. Included in this balance were remediation activities at approximately 182 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company s remediation reserve for these sites at year-end 2010 was $185. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties costs at designated hazardous waste sites are

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Note 24 Other Contingencies and Commitments - Continued
not expected to have a material effect on the company s results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2010 environmental reserves balance of $1,322, $814 related to the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facilities, and pipelines. The remaining $508 was associated with various sites in international downstream ($100), upstream ($329) and other businesses ($79). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company s plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2010 had a recorded liability that was material to the company s results of operations, consolidated financial position or liquidity.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company s liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Refer to Note 25 for a discussion of the company s asset retirement obligations.

Equity Redetermination For crude oil and natural gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron s interests in four producing zones at the Naval Petroleum
Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately $200, and the possible maximum net amount that could be owed to Chevron is estimated at about $150. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies On April 26, 2010, a California appeals court issued a ruling related to the adequacy of an Environmental Impact Report (EIR) supporting the issuance of certain permits by the city of Richmond, California, to replace and upgrade certain facilities at Chevron s refinery in Richmond. Settlement discussions with plaintiffs in the case ended late fourth quarter 2010, and the company continues to evaluate its options going forward, which may include requesting the city to revise the EIR to address the issues identified by the Court of Appeal or other actions. Management believes the outcomes associated with the potential options for the project are uncertain. Due to the uncertainty of the company s future course of action, or potential outcomes of any action or combination of actions, management does not believe an estimate of the financial effects, if any, of the ruling can be made at this time. However, the company s ultimate exposure may be significant to net income in any one future period.

Chevron receives claims from and submits claims to customers; trading partners; U.S. federal, state and local regulatory bodies; governments; contractors; insurers; and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

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

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

Note 25

Asset Retirement Obligations

In accordance with accounting standards for asset retirement obligations (ASC 410), the company records the fair value of a liability for an asset retirement obligation (ARO) when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company s control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. Recognition of the ARO includes: (1) the present value of a liability and offsetting asset, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

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

The following table indicates the changes to the company s before-tax asset retirement obligations in 2010, 2009 and 2008:

	2010	2009	2008
Balance at January 1	**$ 10,175**	$ 9,395	$ 8,253
Liabilities incurred	**129**	144	308
Liabilities settled	**(755)**	(757)	(973)
Accretion expense	**513**	463	430
Revisions in estimated cash flows	**2,426**	930	1,377
Balance at December 31	**$ 12,488**	$ 10,175	$ 9,395

In the table above, the amounts associated with Revisions in estimated cash flows reflect increasing costs to abandon wells, equipment and facilities. The long-term portion of the $12,488 balance at the end of 2010 was $11,788.

Note 26

Other Financial Information

Earnings in 2010 included gains of approximately $700 relating to the sale of nonstrategic properties. Of this amount, approximately $400 and $300 related to downstream and upstream assets, respectively. Earnings in 2009 included gains of approximately $1,000 relating to the sale of nonstrategic properties. Of this amount, approximately $600 and $400 related to downstream and upstream assets, respectively. Earnings in 2008 included gains of approximately $1,200 relating to the sale of nonstrategic properties. Of this amount, approximately $1,000 related to upstream assets.

Other financial information is as follows:

	Year ended December 31		
	2010	2009	2008
Total financing interest and debt costs	**$ 317**	$ 301	$ 256
Less: Capitalized interest	**267**	273	256

Interest and debt expense	**$ 50**	$ 28	$
Research and development expenses	**$ 526**	$ 603	$ 702
Foreign currency effects*	**$ (423)**	$ (744)	$ 862

* Includes $(71), $(194) and $420 in 2010, 2009 and 2008, respectively, for the company s share of equity affiliates foreign currency effects.

The excess of replacement cost over the carrying value of inventories for which the last-in, first-out (LIFO) method is used was $6,975 and $5,491 at December 31, 2010 and 2009, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO profits (charges) of $21, $(168) and $210 were included in earnings for the years 2010, 2009 and 2008, respectively.

The company has $4,617 in goodwill on the Consolidated Balance Sheet related to the 2005 acquisition of Unocal. Under the accounting standard for goodwill (ASC 350), the company tested this goodwill for impairment during 2010 and concluded no impairment was necessary.

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Note 27

Earnings Per Share

Basic earnings per share (EPS) is based upon Net Income Attributable to Chevron Corporation (earnings) and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company and the company s share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company s retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company s stock option programs (refer to Note 20, Stock Options and Other Share-Based Compensation, beginning on page FS-51). The table below sets forth the computation of basic and diluted EPS:

		Year ended December 31	
	2010	2009	2008
Basic EPS Calculation			
Earnings available to common stockholders Basic[1]	**$ 19,024**	$ 10,483	$ 23,931
Weighted-average number of common shares outstanding	**1,996**	1,991	2,037
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,997**	1,992	2,038
Earnings per share of common stock Basic	**$ 9.53**	$ 5.26	$ 11.74
Diluted EPS Calculation			
Earnings available to common stockholders Diluted[1]	**$ 19,024**	$ 10,483	$ 23,931
Weighted-average number of common shares outstanding	**1,996**	1,991	2,037
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**10**	9	12
Total weighted-average number of common shares outstanding	**2,007**	2,001	2,050
Earnings per share of common stock Diluted	**$ 9.48**	$ 5.24	$ 11.67

[1] There was no effect of dividend equivalents paid on stock units or dilutive impact of employee stock-based

awards on
earnings.

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Five-Year Financial Summary
Unaudited

Millions of dollars, except per-share amounts	**2010**	2009	2008	2007	2006
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues[1,2]	**$ 198,198**	$ 167,402	$ 264,958	$ 214,091	$ 204,892
Income from equity affiliates and other income	**6,730**	4,234	8,047	6,813	5,226
Total Revenues and Other Income	**204,928**	171,636	273,005	220,904	210,118
Total Costs and Other Deductions	**172,873**	153,108	229,948	188,630	178,072
Income Before Income Tax Expense	**32,055**	18,528	43,057	32,274	32,046
Income Tax Expense	**12,919**	7,965	19,026	13,479	14,838
Net Income	**19,136**	10,563	24,031	18,795	17,208
Less: Net income attributable to noncontrolling interests	**112**	80	100	107	70
Net Income Attributable to Chevron Corporation	**$ 19,024**	$ 10,483	$ 23,931	$ 18,688	$ 17,138
Per Share of Common Stock					
Net Income Attributable to Chevron[2]					
Basic	**$ 9.53**	$ 5.26	$ 11.74	$ 8.83	$ 7.84
Diluted	**$ 9.48**	$ 5.24	$ 11.67	$ 8.77	$ 7.80
Cash Dividends Per Share	**$ 2.84**	$ 2.66	$ 2.53	$ 2.26	$ 2.01
Balance Sheet Data (at December 31)					
Current assets	**$ 48,841**	$ 37,216	$ 36,470	$ 39,377	$ 36,304
Noncurrent assets	**135,928**	127,405	124,695	109,409	96,324
Total Assets	**184,769**	164,621	161,165	148,786	132,628
Short-term debt	**187**	384	2,818	1,162	2,159
Other current liabilities	**28,825**	25,827	29,205	32,636	26,250
Long-term debt and capital lease obligations	**11,289**	10,130	6,083	6,070	7,679
Other noncurrent liabilities	**38,657**	35,719	35,942	31,626	27,396
Total Liabilities	**78,958**	72,060	74,048	71,494	63,484
Total Chevron Corporation Stockholders Equity	**$ 105,081**	$ 91,914	$ 86,648	$ 77,088	$ 68,935
Noncontrolling interests	**730**	647	469	204	209
Total Equity	**$ 105,811**	$ 92,561	$ 87,117	$ 77,292	$ 69,144

[1] Includes excise, value-added and similar taxes:	**$ 8,591**	$ 8,109	$ 9,846	$ 10,121	$ 9,551
[2] Includes amounts in revenues for buy/sell contracts; associated costs are in					
Total Costs and Other Deductions.	**$**	$	$	$	$ 6,725

Supplemental Information on Oil and Gas Producing Activities
Unaudited

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

Table I - Costs Incurred in Exploration, Property Acquisitions and Development[1]

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2010									
Exploration									
Wells	**$ 99**	**$ 118**	**$ 94**	**$ 244**	**$ 293**	**$ 61**	**$ 909**	**$**	**$**
Geological and geophysical	**67**	**46**	**87**	**29**	**8**	**18**	**255**		
Rentals and other	**121**	**39**	**55**	**47**	**95**	**57**	**414**		
Total exploration	**287**	**203**	**236**	**320**	**396**	**136**	**1,578**		
Property acquisitions[2]									
Proved	**24**			**129**			**153**		
Unproved	**359**	**429**	**160**	**187**		**10**	**1,145**		
Total property acquisitions	**383**	**429**	**160**	**316**		**10**	**1,298**		
Development[3]	**4,446**	**1,611**	**2,985**	**3,325**	**2,623**	**411**	**15,401**	**230**	**343**
Total Costs Incurred[4]	**$ 5,116**	**$ 2,243**	**$ 3,381**	**$ 3,961**	**$ 3,019**	**$ 557**	**$ 18,277**	**$ 230**	**$ 343**
Year Ended December 31, 2009[5]									
Exploration									
Wells	$ 361	$ 70	140	$ 45	275	$ 84	$ 975	$	$
Geological and geophysical	62	70	114	49	17	16	328		
Rentals and other	153	146	92	60	127	43	621		
Total exploration	576	286	346	154	419	143	1,924		
Property acquisitions[2]									
Proved	3						3		
Unproved	29						29		
Total property acquisitions	32						32		

Development[3]	3,338	1,515	3,426	2,698	565	285	11,827	265	69
Total Costs Incurred	$ 3,946	$ 1,801	$ 3,772	$ 2,852	$ 984	$ 428	$ 13,783	$ 265	$ 69
Year Ended December 31, 2008[5]									
Exploration									
Wells	$ 519	$ 47	$ 197	$ 85	$ 248	$ 19	$ 1,115	$	$
Geological and geophysical	66	75	90	42	28	28	329		
Rentals and other	143	135	60	70	46	31	485		
Total exploration	728	257	347	197	322	78	1,929		
Property acquisitions[2]									
Proved	88			169			257		
Unproved	579			280			859		
Total property acquisitions	667			449			1,116		
Development[3]	4,348	1,334	3,723	4,697	540	545	15,187	643	120
Total Costs Incurred[6]	$ 5,743	$ 1,591	$ 4,070	$ 5,343	$ 862	$ 623	$ 18,232	$ 643	$ 120

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations.

See Note 25, Asset Retirement Obligations, on page FS-62.

[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired in nonmonetary transactions.

[3] Includes $745, $121 and $224 costs incurred prior to assignment of proved reserves for consolidated companies in 2010, 2009 and 2008, respectively. Also includes $12 in 2009 for affiliated Other.

[4] Reconciliation of consolidated companies total cost incurred to Upstream capital and exploratory (C&E) expenditures $billions.

Total cost incurred	$ 18.3	
ARO	(2.5)	
Non oil and gas activities	3.1	(Includes LNG and gas-to-liquids $2.3, transportation $0.4, affiliate $0.3, other $0.1)
Upstream C&E	$ 18.9	Reference FS-13 upstream total

[5] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

[6] Excludes costs incurred for oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries Oil and Gas* (Topic 932).

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Table II Capitalized Costs Related to Oil and
Gas Producing Activities
the company s estimated net proved-reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Angola, Chad, Democratic Republic of the Congo, Nigeria, and Republic of the Congo. The Asia geographic area includes activities principally in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, Myanmar, the Partitioned Zone between Kuwait and Saudi Arabia, the Philippines and Thailand. The Europe geographic area includes activity in Denmark, the
Netherlands, Norway and the United Kingdom. The Other Americas geographic region includes activities in Argentina, Brazil, Canada, Colombia, and Trinidad and Tobago. Amounts for TCO represent Chevron s 50 percent equity share of Tengizchevroil, an exploration and production partnership in the Republic of Kazakhstan. The affiliated companies Other amounts are composed of the company s equity interests in Venezuela and Angola. Refer to Note 12, beginning on page FS-43, for a discussion of the company s major equity affiliates.

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

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
At December 31, 2010									
Unproved properties	**$ 2,553**	**$ 1,349**	**$ 359**	**$ 2,561**	**$ 6**	**$ 8**	**$ 6,836**	**$ 108**	**$**
Proved properties and related producing assets	**55,601**	**7,747**	**23,683**	**33,316**	**2,585**	**9,035**	**131,967**	**6,512**	**1,594**
Support equipment	**975**	**265**	**1,282**	**1,421**	**259**	**165**	**4,367**	**985**	
Deferred exploratory wells	**743**	**210**	**611**	**224**	**732**	**198**	**2,718**		
Other uncompleted projects	**2,299**	**3,844**	**4,061**	**3,627**	**3,631**	**362**	**17,824**	**357**	**1,001**
Gross Capitalized Costs	**62,171**	**13,415**	**29,996**	**41,149**	**7,213**	**9,768**	**163,712**	**7,962**	**2,595**
Unproved properties valuation	**967**	**436**	**150**	**200**	**2**		**1,755**	**34**	
Proved producing properties									
Depreciation and depletion	**37,682**	**3,986**	**10,986**	**18,197**	**1,718**	**7,162**	**79,731**	**1,530**	**249**
Support equipment depreciation	**518**	**153**	**600**	**1,126**	**84**	**114**	**2,595**	**402**	
	39,167	**4,575**	**11,736**	**19,523**	**1,804**	**7,276**	**84,081**	**1,966**	**249**

Accumulated provisions									
Net Capitalized Costs	**$ 23,004**	**$ 8,840**	**$ 18,260**	**$ 21,626**	**$ 5,409**	**$ 2,492**	**$ 79,631**	**$ 5,996**	**$ 2,346**
At December 31, 2009[1]									
Unproved properties	$ 2,320	$ 946	$ 321	$ 3,355	$ 7	$ 10	$ 6,959	$ 113	$
Proved properties and related producing assets	51,582	6,033	20,967	29,637	2,507	8,727	119,453	6,404	1,759
Support equipment	810	323	1,012	1,383	162	163	3,853	947	
Deferred exploratory wells	762	216	603	209	440	205	2,435		
Other uncompleted projects	2,384	4,106	3,960	2,936	1,274	192	14,852	284	58
Gross Capitalized Costs	57,858	11,624	26,863	37,520	4,390	9,297	147,552	7,748	1,817
Unproved properties valuation	915	391	163	170	1	(2)	1,638	32	
Proved producing properties									
Depreciation and depletion	34,574	3,182	8,823	15,783	1,579	6,482	70,423	1,150	282
Support equipment depreciation	424	197	526	773	58	102	2,080	356	
Accumulated provisions	35,913	3,770	9,512	16,726	1,638	6,582	74,141	1,538	282
Net Capitalized Costs	$ 21,945	$ 7,854	$ 17,351	$ 20,794	$ 2,752	$ 2,715	$ 73,411	$ 6,210	$ 1,535

[1] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

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

								Affiliated Companies	
	Consolidated Companies								
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
At December 31, 2008[1,2]									
Unproved properties	$ 2,495	$ 900	$ 294	$ 3,300	$ 139	$ 12	$ 7,140	$ 113	$
Proved properties and related producing assets	46,280	4,492	17,495	27,607	2,237	8,548	106,659	5,991	837
Support equipment	717	338	967	1,321	95	137	3,575	888	
Deferred exploratory wells	602	246	499	198	404	169	2,118		
Other uncompleted projects	4,275	1,585	4,226	2,461	904	154	13,605	501	101
Gross Capitalized Costs	54,369	7,561	23,481	34,887	3,779	9,020	133,097	7,493	938
Unproved properties valuation	845	441	202	150	137	(2)	1,773	29	
Proved producing properties									
Depreciation and depletion	30,780	2,743	6,602	13,617	1,289	5,617	60,648	831	163
Support equipment depreciation	382	216	523	690	49	91	1,951	307	
Accumulated provisions	32,007	3,400	7,327	14,457	1,475	5,706	64,372	1,167	163
Net Capitalized Costs[3]	$ 22,362	$ 4,161	$ 16,154	$ 20,430	$ 2,304	$ 3,314	$ 68,725	$ 6,326	$ 775

[1] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

[2] Amounts for Affiliated Companies Other conformed to agreements entered in 2007 and 2008 for Venezuelan affiliates.

[3] Excludes net capitalized costs for oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries Oil and Gas* (Topic 932).

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

The company s results of operations from oil and gas producing activities for the years 2010, 2009 and 2008 are shown in the following table. Net income from exploration and production activities as reported on page FS-41 reflects income taxes computed on an effective rate basis.

Income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page FS-41.

							Consolidated Companies	Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2010									
Revenues from net production									
Sales	**$ 2,540**	**$ 2,441**	**$ 2,278**	**$ 7,221**	**$ 994**	**$ 1,519**	**$ 16,993**	**$ 6,031**	**$ 1,307**
Transfers	**12,172**	**1,038**	**10,306**	**6,242**	**985**	**2,138**	**32,881**		
Total	**14,712**	**3,479**	**12,584**	**13,463**	**1,979**	**3,657**	**49,874**	**6,031**	**1,307**
Production expenses excluding taxes	**(3,338)**	**(805)**	**(1,413)**	**(2,996)**	**(96)**	**(534)**	**(9,182)**	**(347)**	**(152)**
Taxes other than on income	**(542)**	**(102)**	**(130)**	**(85)**	**(334)**	**(2)**	**(1,195)**	**(360)**	**(101)**
Proved producing properties:									
Depreciation and depletion	**(3,639)**	**(907)**	**(2,204)**	**(2,816)**	**(151)**	**(681)**	**(10,398)**	**(432)**	**(131)**
Accretion expense[2]	**(240)**	**(23)**	**(102)**	**(35)**	**(15)**	**(53)**	**(468)**	**(8)**	**(5)**
Exploration expenses	**(193)**	**(173)**	**(242)**	**(289)**	**(175)**	**(75)**	**(1,147)**	**(5)**	
Unproved properties valuation	**(123)**	**(71)**	**(25)**	**(33)**		**(2)**	**(254)**		
Other income (expense)[3]	**(154)**	**(895)**	**(103)**	**(205)**	**109**	**165**	**(1,083)**	**(65)**	**191**
Results before income taxes	**6,483**	**503**	**8,365**	**7,004**	**1,317**	**2,475**	**26,147**	**4,814**	**1,109**
Income tax expense	**(2,273)**	**(304)**	**(5,735)**	**(3,844)**	**(391)**	**(1,477)**	**(14,024)**	**(1,445)**	**(615)**
Results of Producing Operations	**$ 4,210**	**$ 199**	**$ 2,630**	**$ 3,160**	**$ 926**	**$ 998**	**$ 12,123**	**$ 3,369**	**$ 494**
Year Ended December 31, 2009[4]									
Revenues from net production									
Sales	$ 2,278	$ 918	$ 1,767	$ 5,648	$ 543	$ 1,712	$ 12,866	$ 4,043	$ 938
Transfers	9,133	1,555	7,304	4,926	765	1,546	25,229		
Total	11,411	2,473	9,071	10,574	1,308	3,258	38,095	4,043	938
Production expenses excluding taxes	(3,281)	(731)	(1,345)	(2,208)	(94)	(565)	(8,224)	(363)	(240)
Taxes other than on income	(367)	(90)	(132)	(53)	(190)	(4)	(836)	(50)	(96)
Proved producing properties:									
Depreciation and depletion	(3,493)	(486)	(2,175)	(2,279)	(214)	(898)	(9,545)	(381)	(88)
Accretion expense[2]	(194)	(27)	(66)	(70)	(2)	(50)	(409)	(7)	(3)
Exploration expenses	(451)	(203)	(236)	(113)	(224)	(115)	(1,342)		

Unproved properties valuation	(228)	(28)	(11)	(44)			(311)		
Other income (expense)[3]	156	(508)	98	(327)	350	(182)	(413)	(131)	9
Results before income taxes	3,553	400	5,204	5,480	934	1,444	17,015	3,111	520
Income tax expense	(1,258)	(203)	(3,214)	(2,921)	(256)	(901)	(8,753)	(935)	(258)
Results of Producing Operations	$ 2,295	$ 197	$ 1,990	$ 2,559	$ 678	$ 543	$ 8,262	$ 2,176	$ 262

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

[2] Represents accretion of ARO liability. Refer to Note 25, Asset Retirement Obligations, on page FS-62.

[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

[4] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

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

Millions of dollars							Consolidated Companies	Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2008[2]									
Revenues from net production									
Sales	$ 4,882	$ 1,088	$ 2,578	$ 7,969	$ 508	$ 2,938	$ 19,963	$ 4,971	$ 1,599
Transfers	12,868	1,286	8,373	7,179	1,499	2,365	33,570		
Total	17,750	2,374	10,951	15,148	2,007	5,303	53,533	4,971	1,599
Production expenses excluding taxes	(3,822)	(254)	(1,228)	(2,096)	(95)	(620)	(8,115)	(376)	(125)
Taxes other than on income	(716)	(42)	(163)	(263)	(323)	(5)	(1,512)	(41)	(278)
Proved producing properties:									
Depreciation and depletion	(2,286)	(402)	(1,176)	(2,299)	(122)	(928)	(7,213)	(237)	(77)
Accretion expense[3]	(242)	(15)	(60)	(48)	(5)	(39)	(409)	(2)	(1)
Exploration expenses	(370)	(156)	(223)	(178)	(148)	(94)	(1,169)		
Unproved properties valuation	(114)	(7)	(13)	(36)	(1)		(171)		
Other income (expense)[4]	707	(227)	(350)	198	36	509	873	184	105
Results before income taxes	10,907	1,271	7,738	10,426	1,349	4,126	35,817	4,499	1,223
Income tax expense	(3,856)	(591)	(6,051)	(5,697)	(425)	(2,425)	(19,045)	(1,357)	(612)
Results of Producing Operations[5]	$ 7,051	$ 680	$ 1,687	$ 4,729	$ 924	$ 1,701	$ 16,772	$ 3,142	$ 611

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

[2] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

[3] Represents accretion of ARO liability. Refer to Note 25, Asset Retirement Obligations, on page FS-62.

[4] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

[5] Excludes results of producing operations for oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries Oil and Gas* (Topic 932).

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Table IV Results of Operations for Oil and Gas Producing Activities - Unit Prices and Costs[1]

	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
Year Ended December 31, 2010									
Average sales prices									
Liquids, per barrel	**$ 71.59**	**$ 77.77**	**$ 78.00**	**$ 70.96**	**$ 76.43**	**$ 76.10**	**$ 74.02**	**$ 63.94**	**$ 64.92**
Natural gas, per thousand cubic feet	**4.25**	**2.52**	**0.73**	**4.45**	**6.76**	**7.09**	**4.55**	**1.41**	**4.20**
Average production costs, per barrel[2]	**13.11**	**11.86**	**8.57**	**11.71**	**2.55**	**9.42**	**10.96**	**3.14**	**7.37**
Year Ended December 31, 2009[3]									
Average sales prices									
Liquids, per barrel	$ 54.36	$ 65.28	$ 60.35	$ 54.76	$ 54.58	$ 57.19	$ 56.92	$ 47.33	$ 50.18
Natural gas, per thousand cubic feet	3.73	2.01	0.20	4.07	4.24	6.61	3.94	1.54	1.85
Average production costs, per barrel[2]	12.71	12.04	8.85	8.82	2.57	8.87	9.97	3.71	12.42
Year Ended December 31, 2008[3]									
Average sales prices									
Liquids, per barrel	$ 88.43	$ 71.45	$ 91.71	$ 83.67	$ 90.50	$ 93.74	$ 87.44	$ 79.11	$ 69.65
Natural gas, per thousand cubic feet	7.90	2.84		4.55	7.22	9.84	6.02	1.56	3.98
Average production costs, per barrel[2,4]	15.85	4.67	10.00	8.12	2.89	9.59	10.49	5.24	5.32

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

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

[3] Geographic presentation conformed to 2010 consistent with the presentation of the oil and gas reserve tables.

[4] Excludes oil sands in Other Americas and heavy oil in affiliated Other, since 2008 precedes the update to *Extractive Industries Oil and Gas* (Topic 932).

Table V Reserve Quantity Information

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

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

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

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

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the com-
pany maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the vice chairman responsible for the company s worldwide exploration and production activities. The corporate reserves manager, who acts as chairman of the RAC, has more than 30 years experience working in the oil and gas industry and a Master of Science in Petroleum Engineering degree from Stanford University. His experience includes 15 years of managing oil and gas reserves processes. He is the acting chairman of the Society of Petroleum Engineers Oil and Gas Reserves Committee, currently serves on the United Nations Expert Group on Resources Classification and is an active member of the Society of Petroleum Evaluation Engineers. He is also a past member of the Joint Committee on Reserves Evaluator Training and the California Conservation Committee.

All RAC members are degreed professionals, each with more than 15 years experience in various aspects of reserves estimation relating to reservoir engineering, petroleum engineering, earth science, or accounting policy and financial reporting. The members are knowledgeable in SEC guidelines for proved reserves classification and receive annual training on the preparation of reserves estimates. The RAC manages its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

The RAC has the following primary responsibilities: establish the policies and processes used within the operating units to estimate reserves; provide independent reviews and oversight of the business units recommended reserves estimates and changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that

Table V Reserve Quantity Information - Continued

Summary of Net Oil and Gas Reserves

Liquids and Synthetic Oil in Millions of Barrels *Natural Gas in Billions of Cubic Feet*	2010[1] Crude Oil Condensate NGLs	2010[1] Synthetic Oil	2010[1] Natural Gas	2009[1,2] Crude Oil Condensate NGLs	2009[1,2] Synthetic Oil	2009[1,2] Natural Gas	2008[2,3] Crude Oil Condensate NGLs	2008[2,3] Natural Gas
Proved Developed								
Consolidated Companies								
U.S.	**1,045**		**2,113**	1,122		2,314	1,158	2,709
Other Americas	**84**	**352**	**1,490**	66	190	1,678	77	1,853
Africa	**830**		**1,304**	820		978	789	1,209
Asia	**826**		**4,836**	926		5,062	1,094	4,758
Australia	**39**		**881**	50		1,071	46	918
Europe	**136**		**235**	151		302	172	392
Total Consolidated	**2,960**	**352**	**10,859**	3,135	190	11,405	3,336	11,839
Affiliated Companies								
TCO	**1,128**		**1,484**	1,256		1,830	1,369	1,999
Other	**95**	**53**	**70**	97	56	73	263	124
Total Consolidated and Affiliated Companies	**4,183**	**405**	**12,413**	4,488	246	13,308	4,968	13,962
Proved Undeveloped								
Consolidated Companies								
U.S.	**230**		**359**	239		384	312	441
Other Americas	**24**	**114**	**325**	38	270	307	72	515
Africa	**338**		**1,640**	426		2,043	596	1,847
Asia	**187**		**2,357**	245		2,798	362	3,238
Australia	**49**		**5,175**	48		5,174	27	1,044
Europe	**16**		**40**	19		42	30	98
Total Consolidated	**844**	**114**	**9,896**	1,015	270	10,748	1,399	7,183
Affiliated Companies								
TCO	**692**		**902**	690		1,003	807	1,176
Other	**62**	**203**	**1,040**	54	210	990	176	754
Total Consolidated and Affiliated Companies	**1,598**	**317**	**11,838**	1,759	480	12,741	2,382	9,113
Total Proved Reserves	**5,781**	**722**	**24,251**	6,247	726	26,049	7,350	23,075

[1] Based on 12-month average price.

[2] Geographic presentation conformed to 2010.

[3] Based on year-end prices.

reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual,* which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

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

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

Revised Oil and Gas Reporting In December 2008, the SEC issued its final rule, *Modernization of Oil and Gas Reporting.* The disclosure requirements under the final rule became effective for the company with its Form 10-K filing for the year ending December 31, 2009. The final rule changed a number of oil and gas reserve estimation and disclosure requirements under SEC Regulations S-K and S-X. Subsequently, the FASB updated *Extractive Industries Oil and Gas* (Topic 932) to align the oil and gas reserves estimation and disclosure requirements with the SEC s final rule. The new disclosure requirements have been applied to data reported for 2009 and 2010.

Proved Undeveloped Reserve Quantities At the end of 2010, proved undeveloped reserves for consolidated companies totaled 2.6 billion barrels of oil-equivalent (BOE). Approximately 63 percent of these reserves are attributed to natural gas, of which about half were located in Australia. Crude oil, condensate and natural gas liquids (NGLs) accounted for about 32 percent of the total, with the largest concentration of these reserves in Africa, Asia and the United States. Synthetic oil accounted for the balance of the proved undeveloped reserves and was located in Canada in the Other Americas region.

Table V Reserve Quantity Information - Continued

Proved undeveloped reserves of equity affiliates amounted to 1.3 billion BOE. At year-end, crude oil, condensate and NGLs represented 59 percent of these reserves, with TCO accounting for the majority of this amount. Natural gas represented 25 percent of the total, with approximately 45 percent of those reserves from TCO. The balance is attributed to synthetic oil in Venezuela in the Other region.

In 2010, a total of 447 million BOE was transferred from proved undeveloped to proved developed for consolidated companies. In Other Americas, 171 million BOE were transferred, primarily due to startup of a synthetic crude expansion project in Canada. In the Africa region, 135 million BOE were transferred to proved developed as a result of development drilling in Nigeria and Angola and the start-up of a natural gas processing plant in Nigeria. Transfers in Asia and the United States accounted for most of the remainder. Proved undeveloped reserves for affiliated companies declined slightly, with 13 million BOE transferred to proved developed.

There were no material downward revisions of proved undeveloped reserves for consolidated or affiliated companies.

Investment to Convert Proved Undeveloped to Proved Developed Reserves During 2010, investments totaling approximately $8.3 billion were made by consolidated companies and equity affiliates to advance the development of proved undeveloped reserves. In Australia, $2.6 billion was expended, which was primarily driven by construction activities at the Gorgon LNG project. In the Africa region, $2.1 billion was expended on various projects, including offshore development projects in Nigeria and Angola. In Nigeria, construction progressed on a deepwater project and development activities continued at a natural gas processing plant. In Angola, offshore development drilling was progressed along with several gas injection projects. In the United States, expenditures totaled $1.1 billion for three offshore development projects in the Gulf of Mexico and various smaller development projects. In the Asia region, expenditures during the year totaled $0.9 billion, which included construction of a gas processing facility in Thailand, a gas development project in China and the completion of a steam-flood project in Indonesia. In Other Americas, development expenditures totaled $0.8 billion for a variety of projects, including a synthetic crude project in Canada. In Europe, $0.1 billion was expended on various development projects. Affiliated companies expended $0.7 billion, primarily on an LNG project in Angola.

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

At year-end 2010, the company held approximately 1.7 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more. The reserves are held by consolidated and affiliated companies and the majority of these reserves are in locations where the company has a proven track record of developing major projects.

In Africa, approximately 330 million BOE is related to deepwater and natural gas developments in Nigeria and Angola. Major Nigerian deepwater development projects include Agbami, which started production in 2008 and has ongoing development activities to maintain full utilization of infrastructure capacity, and the Usan development, which is under construction and is expected to enter production in 2012. Also in Nigeria, various fields and infrastructure associated with the Escravos Gas Projects are currently under development. In Angola, the Tombua-Landana deepwater project became operational in 2009. Ongoing development drilling is expected to bring this field to maximum production in 2011.

In Asia, approximately 230 million BOE are related to continued development of the Pattani Field in the Gulf of Thailand and contractual constraints at the Malampaya Field (Philippines). The timing of compression installation aligns with natural field declines and/or to meet contractual requirements. Ongoing development is scheduled to maintain production within the infrastructure constraints.

In Australia, approximately 130 million BOE remain undeveloped over five years due to future compression projects at the North West Shelf Venture, scheduled for 2013.

In the United States, approximately 70 million BOE remain proved undeveloped, primarily related to a steamflood expansion.

Affiliated companies hold approximately 940 million BOE of proved undeveloped reserves held for five years or more. The TCO affiliate in Kazakhstan accounts for approximately 800 million BOE. Field production is constrained by plant capacity limitations. Further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion.

In Venezuela, the affiliate that operates the Hamaca Field s synthetic heavy oil upgrading operation accounts for about 140 million BOE of proved undeveloped reserves held over five years. Development drilling continues at Hamaca to optimize utilization of upgrader capacity.

Annually, the company assesses whether any changes have occurred in facts or circumstances, such as changes to development plans, regulations or government policies, that would warrant a revision to reserve estimates. For 2010, this assessment did not result in any material changes in reserves classified as proved undeveloped. Over the past three years, the ratio of proved undeveloped reserves to total proved

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Table V Reserve Quantity Information - Continued

reserves has ranged between 35 percent and 39 percent. The consistent completion of major capital projects has kept the ratio in a narrow range over this time period.

Proved Reserve Quantities At December 31, 2010, proved reserves for the company s consolidated operations were 7.7 billion BOE. (Refer to the term Reserves on page E-26 for the definition of oil-equivalent reserves.) Approximately 22 percent of the total reserves were located in the United States. For the company s interests in equity affiliates, proved reserves were 2.8 billion BOE, 79 percent of which were associated with the company s 50 percent ownership in TCO.

Aside from the Tengiz Field in the TCO affiliate, no single property accounted for more than 5 percent of the company s total oil-equivalent proved reserves. About 25 other individual properties in the company s portfolio of assets each contained between 1 percent and 5 percent of the company s oil-equivalent proved reserves, which in the aggregate accounted for 49 percent of the company s total oil-equivalent proved reserves. These properties were geographically dispersed, located in the United States, Canada, South America, West Africa, Asia, and Australia.

In the United States, total proved reserves at year-end 2010 were 1.7 billion BOE. California properties accounted for 43 percent of the U.S. reserves, with most classified as heavy oil. Because of heavy oil s high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company s heavy-oil fields in California employ a continuous steamflooding process. The Gulf of Mexico region contains 21 percent of the U.S. reserves, with liquids representing about 15 percent of reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Other U.S. areas represent the remaining 36 percent of U.S. reserves, which are about evenly split between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO_2 injection.

For the three years ending December 31, 2010, the pattern of net reserve changes shown in the following tables are not necessarily indicative of future trends. Apart from acquisitions, the company s ability to add proved reserves is affected by, among other things, events and circumstances that are outside the company s control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties and civil unrest.

The company s estimated net proved reserves of crude oil, condensate, natural gas liquids and synthetic oil, and changes thereto for the years 2008, 2009 and 2010 are shown in the table on the following page. The company s estimated net proved reserves of natural gas are shown on page FS-77.

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Table V Reserve Quantity Information - Continued
Net Proved Reserves of Crude Oil, Condensate, Natural Gas Liquids and Synthetic Oil

	Consolidated Companies								Affiliated Companies			Total Consolidated and Affiliated
Millions of barrels	U.S.	Other Americas[1]	Africa	Asia	Australia	Europe	Synthetic Oil[2,3]	Total	TCO	Synthetic Oil[2,4]	Other[5]	Companies
Reserves at January 1, 2008[6]	1,624	165	1,500	1,023	84	269		4,665	1,989		433	7,087
Changes attributable to:												
Revisions	(16)	(1)	2	574	1	(24)		536	249		18	803
Improved recovery	5	3	1	18				27			10	37
Extensions and discoveries	17	8	3	5				33				33
Purchases	1							1				1
Sales[7]	(7)							(7)				(7)
Production	(154)	(26)	(121)	(164)	(12)	(43)		(520)	(62)		(22)	(604)
Reserves at December 31, 2008[6,8]	1,470	149	1,385	1,456	73	202		4,735	2,176		439	7,350
Changes attributable to:												
Revisions	63	(29)	(46)	(121)	18	10	460	355	(184)	266	(269)	168
Improved recovery	2		48					50	36			86
Extensions and discoveries	6	13	10	3	20			52				52
Purchases												
Sales	(3)	(6)						(9)				(9)
Production	(177)	(23)	(151)	(167)	(13)	(42)		(573)	(82)		(19)	(674)
Reserves at December 31, 2009[6,8]	1,361	104	1,246	1,171	98	170	460	4,610	1,946	266	151	6,973
Changes attributable to:												
Revisions	**63**	**12**	**17**	**(26)**	**3**	**19**	**15**	**103**	**(33)**		**12**	**82**
Improved recovery	**11**	**3**	**58**	**2**				**74**			**3**	**77**
Extensions and discoveries	**19**	**19**	**9**	**16**				**63**				**63**
Purchases				**11**				**11**				**11**
Sales	**(1)**							**(1)**				**(1)**
Production	**(178)**	**(30)**	**(162)**	**(161)**	**(13)**	**(37)**	**(9)**	**(590)**	**(93)**	**(10)**	**(9)**	**(702)**
Reserves at December 31, 2010[8]	**1,275**	**108**	**1,168**	**1,013**	**88**	**152**	**466**	**4,270**	**1,820**	**256**	**157**	**6,503**

[1] Ending reserve balances in North America and South America were 14, 12, 19 and 94, 92, 130 in 2010, 2009 and 2008, respectively.

[2] Prospective reporting effective December 31, 2009.

[3] Reserves associated with Canada.

[4] Reserves associated with Venezuela that were reported in affiliated other as heavy oil in 2008.

[5] Ending reserve balances in Africa and South America were 36, 31, 19 and 121, 120, 420 in 2010, 2009 and 2008, respectively.

[6] Geographic presentation conformed to 2010.

[7] Includes reserves disposed of through nonmonetary transactions.

[8] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-25 for the definition of a PSC). PSC-related reserve quantities are 24 percent, 26 percent and 32 percent for consolidated companies for 2010, 2009 and 2008, respectively.

Noteworthy amounts in the categories of liquids proved reserve changes for 2008 through 2010 are discussed below:

Revisions In 2008, net revisions increased reserves by 536 million barrels for worldwide consolidated companies and increased reserves by 267 million barrels for equity affiliates. For consolidated companies, the largest increase was in the Asia region, which added 574 million barrels. The majority of the increase was in the Partitioned Zone, as a result of a concession extension, and Indonesia. In Indonesia, reserves increased due mainly to the impact of lower year-end prices on the reserve calculations for production-sharing contracts, as well as a result of development drilling and improved waterflood and steamflood performance. Upward revisions were also recorded in Kazakhstan and Azerbaijan and were mainly associated with the effect of lower year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. These increases were offset by downward revisions in Europe and the United States. For affiliated companies, the 249 million-barrel increase for TCO was due to the effect of lower year-end prices on the royalty
determination and the effect of facility optimization at the Tengiz and Korolev fields.

In 2009, net revisions increased reserves by 355 million barrels for worldwide consolidated companies and decreased reserves by 187 million barrels for equity affiliates. For consolidated companies, the largest increase was 460 million barrels in the Other Americas region due to the inclusion of synthetic oil related to Canadian oil sands. In the United States, reserves increased 63 million barrels as a result of development drilling and performance revisions. The increases were partially offset by decreases of 121 million barrels in Asia and 46 million barrels in Africa. In Asia, decreases in Indonesia and Azerbaijan were driven by the effect of higher 12-month average prices on the calculation of reserves associated with production-sharing contracts and the effect of reservoir performance revisions. In Africa, reserves in Nigeria declined as a result of higher prices on production-sharing contracts as well as reservoir performance.

For affiliated companies, TCO declined by 184 million barrels primarily due to the effect of higher 12-month average

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Table V Reserve Quantity Information - Continued

prices on royalty determination. For Other affiliated companies, 266 million barrels of heavy crude oil were reclassified to synthetic oil for the activities in Venezuela.

In 2010, net revisions increased reserves 103 million barrels for consolidated companies and decreased reserves 21 million barrels for affiliated companies. For consolidated companies, improved reservoir performance and recovery factors accounted for a majority of the 63 million barrel increase in the United States. Increases in the other regions were partially offset by the Asia region, which decreased as a result of the effect of higher prices on production-sharing contracts in Kazakhstan. For affiliated companies, the price effect on royalty determination at TCO decreased reserves by 33 million barrels. This was partially offset by improved reservoir performance and development drilling in Venezuela.

Improved Recovery In 2008, improved recovery increased worldwide liquids volumes by 37 million barrels. For consolidated companies, the largest addition was in the Asia region related to gas reinjection in Kazakhstan. Affiliated companies increased reserves 10 million barrels due to improved secondary recovery at Boscan.

In 2009, improved recovery increased liquids volumes by 86 million barrels worldwide. Consolidated companies accounted for 50 million barrels. The largest addition was related to improved secondary recovery in Nigeria. Affiliated companies increased reserves 36 million barrels due to improvements related to the TCO Sour Gas Injection/Second Generation Plant (SGI/SGP) facilities.

In 2010, improved recovery increased volumes by 77 million barrels worldwide. For consolidated companies, reserves in Africa increased 58 million barrels due primarily to secondary recovery performance in Nigeria. Reserves in the United States increased 11 million, primarily in California. Affiliated companies increased reserves 3 million barrels.

Extensions and Discoveries In 2008, extensions and discoveries increased consolidated company reserves 33 million barrels worldwide. The United States increased reserves 17 million barrels, primarily in the Gulf of Mexico. The Africa, Asia, and Other Americas regions increased reserves 16 million barrels with no one country resulting in additions greater than 5 million barrels.

In 2009, extensions and discoveries increased liquids volumes by 52 million barrels worldwide. The largest additions were 20 million barrels in the Australia region related to the Gorgon Project and 13 million barrels in the Other Americas region related to delineation drilling in Argentina. Africa and the United States accounted for 10 million barrels and 6 million barrels, respectively.

In 2010, extensions and discoveries increased consolidated companies reserves 63 million barrels worldwide. The United States and Other Americas each increased reserves 19 million barrels, and Asia increased reserves 16 million barrels. No single area in the United States was individually significant. Drilling activity in Argentina and Brazil accounted for the majority of the increase in Other Americas. In Asia, the increase was primarily related to activity in Azerbaijan.

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Table V Reserve Quantity Information - Continued
Net Proved Reserves of Natural Gas

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
Billions of cubic feet (BCF)	U.S.	Other Americas[1]	Africa	Asia	Australia	Europe	Total	TCO	Other[2]	
Reserves at January 1, 2008[3]	3,677	2,378	3,049	7,207	2,105	721	19,137	2,748	255	22,140
Changes attributable to:										
Revisions	(28)	154	60	1,073	(5)	(88)	1,166	498	632	2,296
Improved recovery										
Extensions and discoveries	108	1		23			132			132
Purchases	66			441			507			507
Sales[4]	(124)						(124)			(124)
Production[5]	(549)	(165)	(53)	(748)	(138)	(143)	(1,796)	(71)	(9)	(1,876)
Reserves at December 31, 2008[3,6]	3,150	2,368	3,056	7,996	1,962	490	19,022	3,175	878	23,075
Changes attributable to:										
Revisions	39	(126)	4	493	166	(7)	569	(237)	193	525
Improved recovery										
Extensions and discoveries	53	1	3	54	4,276		4,387			4,387
Purchases										
Sales	(33)	(84)					(117)			(117)
Production[5]	(511)	(174)	(42)	(683)	(159)	(139)	(1,708)	(105)	(8)	(1,821)
Reserves at December 31, 2009[3,6]	2,698	1,985	3,021	7,860	6,245	344	22,153	2,833	1,063	26,049
Changes attributable to:										
Revisions	**220**	**4**	**(20)**	**(31)**	**(22)**	**46**	**197**	**(324)**	**56**	**(71)**
Improved recovery	**1**	**1**					**2**			**2**
Extensions and discoveries	**36**	**4**		**59**		**11**	**110**			**110**
Purchases	**3**			**4**			**7**			**7**
Sales	**(7)**						**(7)**			**(7)**
Production[5]	**(479)**	**(179)**	**(57)**	**(699)**	**(167)**	**(126)**	**(1,707)**	**(123)**	**(9)**	**(1,839)**
Reserves at December 31, 2010[6]	**2,472**	**1,815**	**2,944**	**7,193**	**6,056**	**275**	**20,755**	**2,386**	**1,110**	**24,251**

[1] Ending reserve balances in North America and South America were 21, 23, 24 and 1,794, 1,962 and 2,344 in 2010, 2009 and 2008, respectively.

[2] Ending reserve balances in Africa and South America were 953, 898, 700 and 157, 165, 178 in 2010, 2009 and 2008, respectively.

[3] Geographic presentation conformed to 2010.

[4] Includes reserves disposed of through nonmonetary transactions.

[5] Total as sold volumes are 4.5 BCF, 4.5 BCF and 4.6 BCF for 2010, 2009 and 2008, respectively.

[6] Includes reserve quantities related to production-sharing contracts (PSC) (refer to page E-25 for the definition of a PSC). PSC-related reserve quantities are 29 percent, 31 percent and 40 percent for consolidated companies for 2010, 2009 and 2008, respectively.

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2008 through 2010 are discussed below:

Revisions In 2008, net revisions increased reserves for consolidated companies by 1,166 BCF and increased reserves for affiliated companies by 1,130 BCF. In the Asia region, positive revisions totaled 1,073 BCF for consolidated companies. Almost half of the increase was attributed to the Karachaganak Field in Kazakhstan, due mainly to the effects of low year-end prices on the production-sharing contract and the results of development drilling and improved recovery. Other large upward revisions were recorded for the Pattani Field in Thailand due to a successful drilling campaign. In the Other Americas region, improved field performance and new contracts in Colombia, and Trinidad and Tobago, respectively, accounted for most of the 154 BCF increase.

For the TCO affiliate in Kazakhstan, an increase of 498 BCF reflected the impacts of lower year-end prices on royalty determination and facility optimization. Reserves associated with the Angola LNG project accounted for a majority of the 632 BCF increase in Other affiliated companies.

In 2009, net revisions increased reserves 569 BCF for consolidated companies and decreased reserves 44 BCF for affiliated companies. For consolidated companies, net increases were 493 BCF in Asia, primarily as a result of reservoir studies in Bangladesh and development drilling in Thailand. These results were partially offset by a downward revision due to the impact of higher prices on production-sharing contracts in Myanmar. In the Australia region, the 166 BCF increase in reserves resulted from improved reservoir performance and compression. In the Other Americas region, reserves decreased 126 BCF, driven primarily by the effect of higher prices on production-sharing contracts in Trinidad and Tobago. In the United States, a net increase of 39 BCF was the result of development drilling in the Gulf of Mexico, partially offset by performance revisions in the California and mid-continent areas.

For equity affiliates, a downward revision of 237 BCF at TCO was due to the effect of higher prices on royalty determination and an increase in gas injection for SGI/SGP facilities. This decline was partially offset by performance and drilling opportunities related to the Angola LNG project.

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Table V Reserve Quantity Information - Continued

In 2010, net revisions increased reserves by 197 BCF for consolidated companies, which was more than offset by a 268 BCF decrease in net revisions for affiliated companies. For consolidated companies, a net increase in the United States of 220 BCF, primarily in the mid-continent area and the Gulf of Mexico, was the result of a number of small upward revisions related to improved reservoir performance and drilling activity, none of which were individually significant. The increase was partially offset by downward revisions due to the impact of higher prices on production-sharing contracts in the Asia region. For equity affiliates, a downward revision of 324 BCF at TCO was due to the price effect on royalty determination and a change in the variable-royalty calculation. This decline was partially offset by the recognition of additional reserves related to the Angola LNG project.

Extensions and Discoveries In 2009, worldwide extensions and discoveries of 4,387 BCF were attributed to consolidated companies. In Australia, the Gorgon Project accounted for all of the 4,276 BCF additions. In Asia, development drilling in Thailand accounted for the majority of the increase. In the United States, delineation drilling in California accounted for the majority of the increase.

Sales In 2009, worldwide sales of 117 BCF were related to consolidated companies. For the Other Americas region, the sale of properties in Argentina accounted for 84 BCF. The sale of properties in the Gulf of Mexico accounted for the majority of the 33 BCF decrease in the United States.

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

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of the FASB. Estimated future cash inflows from production are computed by applying 12-month average prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management s estimate of the company s expected future cash flows or value of proved oil and gas reserves. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The valuation prescribed by the FASB requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company s future cash flows or value of its oil and gas reserves. In the following table, Standardized Measure Net Cash Flows refers to the standardized measure of discounted future net cash flows.

								Affiliated Companies		Total Consolidated and Affiliated Companies
	Consolidated Companies									
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other	
At December 31, 2010										
Future cash inflows from production[1]	**$ 101,281**	**$ 48,068**	**$ 90,402**	**$ 101,553**	**$ 52,635**	**$ 13,618**	**$ 407,557**	**$ 124,970**	**$ 31,188**	**$ 563,715**
Future production costs	**(36,609)**	**(22,118)**	**(19,591)**	**(30,793)**	**(9,191)**	**(5,842)**	**(124,144)**	**(7,298)**	**(4,172)**	**(135,614)**
Future development costs	**(6,661)**	**(6,953)**	**(12,239)**	**(11,690)**	**(13,160)**	**(708)**	**(51,411)**	**(8,777)**	**(2,254)**	**(62,442)**
Future income taxes	**(20,307)**	**(7,337)**	**(34,405)**	**(26,355)**	**(9,085)**	**(4,031)**	**(101,520)**	**(30,763)**	**(12,919)**	**(145,202)**
Undiscounted future net cash flows	**37,704**	**11,660**	**24,167**	**32,715**	**21,199**	**3,037**	**130,482**	**78,132**	**11,843**	**220,457**
10 percent midyear annual discount for timing of	**(13,218)**	**(6,751)**	**(9,221)**	**(12,287)**	**(15,282)**	**(699)**	**(57,458)**	**(43,973)**	**(6,574)**	**(108,005)**

estimated cash flows										
Standardized Measure Net Cash Flows	**$ 24,486**	**4,909**	**$ 14,946**	**$ 20,428**	**$ 5,917**	**$ 2,338**	**$ 73,024**	**$ 34,159**	**$ 5,269**	**$ 112,452**
At December 31, 2009										
Future cash inflows from production[2]	$ 81,332	$ 39,251	$ 75,338	$ 91,993	$ 49,875	$ 11,988	$ 349,777	$ 97,793	$ 23,825	$ 471,395
Future production costs	(35,295)	(27,716)	(22,459)	(31,843)	(8,648)	(5,842)	(131,803)	(6,923)	(4,765)	(143,491)
Future development costs	(7,027)	(3,711)	(14,715)	(12,884)	(12,371)	(561)	(51,269)	(8,190)	(3,986)	(63,445)
Future income taxes	(13,662)	(3,674)	(22,503)	(18,905)	(10,484)	(3,269)	(72,497)	(23,357)	(7,774)	(103,628)
Undiscounted future net cash flows	25,348	4,150	15,661	28,361	18,372	2,316	94,208	59,323	7,300	160,831
10 percent midyear annual discount for timing of estimated cash flows	(8,822)	(2,275)	(5,882)	(11,722)	(14,764)	(467)	(43,932)	(34,937)	(4,450)	(83,319)
Standardized Measure Net Cash Flows	$ 16,526	1,875	$ 9,779	$ 16,639	$ 3,608	$ 1,849	$ 50,276	$ 24,386	$ 2,850	$ 77,512
At December 31, 2008										
Future cash inflows from production[2]	$ 66,174	$ 12,051	$ 52,344	$ 75,855	$ 14,368	$ 10,989	$ 231,781	$ 51,252	$ 13,968	$ 297,001
Future production costs	(45,738)	(3,369)	(20,302)	(33,817)	(5,989)	(6,005)	(115,220)	(14,502)	(2,319)	(132,041)
Future development costs	(6,099)	(1,367)	(19,001)	(15,298)	(909)	(1,132)	(43,806)	(10,140)	(1,551)	(55,497)
Future income taxes	(5,091)	(3,095)	(9,581)	(10,278)	(2,241)	(2,257)	(32,543)	(7,517)	(5,223)	(45,283)
Undiscounted future net cash flows	9,246	4,220	3,460	16,462	5,229	1,595	40,212	19,093	4,875	64,180
10 percent midyear annual discount	(2,318)	(1,406)	(1,139)	(7,042)	(2,455)	(191)	(14,551)	(11,261)	(2,966)	(28,778)

for timing of estimated cash flows									
Standardized Measure Net Cash Flows	$ 6,928	$ 2,814	$ 2,321	$ 9,420	$ 2,774	$ 1,404	$ 25,661	$ 7,832	$ 1,909	$ 35,402

[1] Based on 12-month average price.

[2] Based on year-end prices.

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

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

Millions of dollars	Consolidated Companies	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2008	$ 97,049	$ 41,758	$ 138,807
Sales and transfers of oil and gas produced net of production costs	(43,906)	(5,750)	(49,656)
Development costs incurred	13,682	763	14,445
Purchases of reserves	233		233
Sales of reserves	(542)		(542)
Extensions, discoveries and improved recovery less related costs	646	83	729
Revisions of previous quantity estimates	37,853	3,718	41,571
Net changes in prices, development and production costs	(169,046)	(51,696)	(220,742)
Accretion of discount	17,458	5,976	23,434
Net change in income tax	72,234	14,889	87,123
Net change for 2008	(71,388)	(32,017)	(103,405)
Present Value at December 31, 2008	$ 25,661	$ 9,741	$ 35,402
Sales and transfers of oil and gas produced net of production costs	(27,559)	(4,209)	(31,768)
Development costs incurred	10,791	335	11,126
Purchases of reserves			
Sales of reserves	(285)		(285)
Extensions, discoveries and improved recovery less related costs	3,438	697	4,135
Revisions of previous quantity estimates	3,230	(4,343)	(1,113)
Net changes in prices, development and production costs	51,528	30,915	82,443
Accretion of discount	4,282	1,412	5,694
Net change in income tax	(20,810)	(7,312)	(28,122)
Net change for 2009	24,615	17,495	42,110
Present Value at December 31, 2009	$ 50,276	$ 27,236	$ 77,512

Sales and transfers of oil and gas produced net of production costs	(39,499)	(6,377)	(45,876)
Development costs incurred	12,042	572	12,614
Purchases of reserves	513		513
Sales of reserves	(47)		(47)
Extensions, discoveries and improved recovery less related costs	5,194	63	5,257
Revisions of previous quantity estimates	10,156	974	11,130
Net changes in prices, development and production costs	43,887	19,878	63,765
Accretion of discount	8,391	3,797	12,188
Net change in income tax	(17,889)	(6,715)	(24,604)
Net change for 2010	22,748	12,192	34,940
Present Value at December 31, 2010	$ 73,024	$ 39,428	$ 112,452

EXHIBIT INDEX

Exhibit No.	Description
3.1	Restated Certificate of Incorporation of Chevron Corporation, dated May 30, 2008, filed as Exhibit 3.1 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2008, and incorporated herein by reference.
3.2	By-Laws of Chevron Corporation, as amended September 29, 2010, filed as Exhibit 3.1 to Chevron Corporation s Current Report on Form 8-K dated September 30, 2010, and incorporated herein by reference.
4.1	Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the corporation and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Commission upon request.
4.2	Confidential Stockholder Voting Policy of Chevron Corporation, filed as Exhibit 4.2 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.1	Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan, filed as Exhibit 10.1 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.2	Chevron Incentive Plan, filed as Exhibit 10.2 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.3	Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.3 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.4	Chevron Corporation Deferred Compensation Plan for Management Employees, as amended and restated on December 7, 2005, filed as Exhibit 10.5 to Chevron Corporation s Current Report on Form 8-K dated December 13, 2005, and incorporated herein by reference.
10.5	Chevron Corporation Deferred Compensation Plan for Management Employees II, filed as Exhibit 10.5 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.6	Chevron Corporation Retirement Restoration Plan, filed as Exhibit 10.6 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.7	Chevron Corporation ESIP Restoration Plan, filed as Exhibit 10.7 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.8	Texaco Inc. Stock Incentive Plan, adopted May 9, 1989, as amended May 13, 1993, and May 13, 1997, filed as Exhibit 10.13 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.
10.9	Supplemental Pension Plan of Texaco Inc., dated June 26, 1975, filed as Exhibit 10.14 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.
10.10	Supplemental Bonus Retirement Plan of Texaco Inc., dated May 1, 1981, filed as Exhibit 10.15 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.

10.11	Texaco Inc. Director and Employee Deferral Plan approved March 28, 1997, filed as Exhibit 10.16 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2001, and incorporated herein by reference.
10.12	Summary of Chevron Incentive Plan Award Criteria, filed as Exhibit 10.13 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.13	Chevron Corporation Change in Control Surplus Employee Severance Program for Salary Grades 41 through 43, filed as Exhibit 10.1 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.
10.14	Chevron Corporation Benefit Protection Program, filed as Exhibit 10.2 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.
10.15	Form of Terms and Conditions for Awards under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.1 to Chevron Corporation s Current Report on Form 8-K dated February 1, 2011, and incorporated herein by reference.

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Exhibit No.	Description
10.16	Form of Restricted Stock Unit Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.16 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference.
10.17	Form of Retainer Stock Option Agreement under the Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan, filed as Exhibit 10.17 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference.
10.18	Form of Stock Units Agreement under the Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan, filed as Exhibit 10.19 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.19	Employment Agreement, dated October 3, 2002, between Chevron Corporation and Charles A. James, filed as Exhibit 10.19 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference.
10.20	Termination Agreement, dated January 5, 2010, between Chevron Corporation and Charles A. James, filed as Exhibit 10.20 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference.
12.1*	Computation of Ratio of Earnings to Fixed Charges (page E-3).
21.1*	Subsidiaries of Chevron Corporation (pages E-4 through E-5).
23.1*	Consent of PricewaterhouseCoopers LLP (page E-6).
24.1 to 24.14*	Powers of Attorney for directors and certain officers of Chevron Corporation, authorizing the signing of the Annual Report on Form 10-K on their behalf.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Executive Officer (page E-21).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Financial Officer (page E-22).
32.1*	Section 1350 Certification of the company s Chief Executive Officer (page E-23).
32.2*	Section 1350 Certification of the company s Chief Financial Officer (page E-24).
99.1*	Definitions of Selected Energy and Financial Terms (pages E-25 through E-27).
99.2*	Mine Safety Disclosure.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.LAB*	XBRL Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.

Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and is otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

* Filed herewith.

Copies of above exhibits not contained herein are available to any security holder upon written request to the Corporate Governance Department, Chevron Corporation, 6001 Bollinger Canyon Road, San Ramon, California 94583-2324.

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