CHEVRON CORP
Form 10-K
February 28, 2008

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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, 2007**

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 1-368-2
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 Number)	(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 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. þ

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 $179,575,224,370 (As of June 30, 2007)

Number of Shares of Common Stock outstanding as of February 22, 2008 2,076,680,120

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2008 Annual Meeting and 2008 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company s 2008 Annual Meeting of Stockholders (in Part III)

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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 our 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 crude oil and natural gas prices; refining margins and marketing margins; chemicals margins; actions of competitors; timing of exploration expenses; 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 OPEC (Organization of Petroleum Exporting Countries); the potential liability for remedial actions 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 pending or future litigation; the company s acquisition or disposition of assets; gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, 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 and 33 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,[1] 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. Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and also marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemical operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant oil additives.

On August 10, 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. Discussion of the Unocal acquisition is in Note 2 on page FS-34.

A list of the company s major subsidiaries is presented on pages E-4 and E-5. As of December 31, 2007, Chevron had approximately 65,000 employees (including about 6,000 service station employees). Approximately 31,000, or 48 percent, of the company s employees 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 and 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 to 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 and transportation entities in the sale or acquisition of various goods or services in many national and international markets.

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

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Operating Environment

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

Chevron Strategic Direction

Chevron s primary objective is to create value and achieve sustained financial returns from its operations that will enable it to outperform its competitors. As a foundation for achieving this objective, the company has established the following strategies:

Strategies for Major Businesses

Upstream grow profitably in core areas, build new legacy positions and commercialize the company s natural gas equity resource base while growing a high-impact global gas business

Downstream improve base-business returns and selectively grow, with a focus on integrated value creation

The company also continues to invest in renewable-energy technologies, with an objective of capturing profitable positions in important renewable sources of energy.

Enabling Strategies Companywide

Invest in people to achieve the company s strategies

Leverage technology to deliver superior performance and growth

Build organizational capability to deliver world-class performance in operational excellence, cost reduction, capital stewardship and profitable growth

(b) Description of Business and Properties

The upstream, downstream and chemicals activities of the company and its equity affiliates are widely dispersed geographically, with operations in North America, South America, Europe, Africa, the Middle East, Asia and Australasia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2007, and assets as of the end of 2007 and 2006 for the United States and the company s international geographic areas are in Note 8 to the Consolidated Financial Statements beginning on page FS-37. In addition, similar comparative data for the company s investments in and income from equity affiliates and property, plant and equipment are in Notes 11 and 12 on pages FS-40 to FS-42.

Capital and Exploratory Expenditures

Total reported expenditures for 2007 were $20 billion, including $2.3 billion for Chevron s share of expenditures by affiliated companies, which did not require cash outlays by the company. In 2006 and 2005, expenditures were $16.6 billion and $11.1 billion, respectively, including the company s share of affiliates expenditures of $1.9 billion and $1.7 billion in the corresponding periods. The 2005 amount excludes $17.3 billion for the acquisition of Unocal.

Of the $20 billion in expenditures for 2007, 78 percent, or $15.5 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2006 and 2005. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the three years, reflecting the company s continuing focus on opportunities that are available outside the United States.

In 2008, the company estimates capital and exploratory expenditures will be 15 percent higher at $22.9 billion, including $2.6 billion of spending by affiliates. About three-fourths of the total, or $17.5 billion, is budgeted for exploration and production activities, with $12.7 billion of that amount outside the United States.

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

Upstream Exploration and Production

The table on the following page summarizes the net production of liquids and natural gas for 2007 and 2006 by the company and its affiliates.

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Net Production of Crude Oil and Natural Gas Liquids and Natural Gas

	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)	
	2007	2006	2007	2006	2007	2006
United States:						
California	221	224	205	207	97	101
Gulf of Mexico	214	224	118	114	576	661
Texas (Onshore)	153	150	77	79	457	425
Other States	155	165	60	62	569	623
Total United States	743	763	460	462	1,699	1,810
Africa:						
Angola	179	164	171	156	48	47
Nigeria	129	144	126	139	15	29
Chad	32	35	31	34	4	4
Republic of the Congo	8	12	7	11	7	8
Democratic Republic of the Congo	3	3	3	3	2	2
Total Africa	351	358	338	343	76	90
Asia-Pacific:						
Thailand	224	216	71	73	916	856
Partitioned Neutral Zone (PNZ)[1]	112	114	109	111	17	19
Australia	100	99	39	39	372	360
Kazakhstan	66	62	41	38	149	143
Azerbaijan	61	47	60	46	5	4
Bangladesh	47	21	2		275	126
China	26	26	22	23	22	18
Philippines	26	24	5	6	126	108
Myanmar	17	15			100	89
Total Asia-Pacific	679	624	349	336	1,982	1,723
Indonesia	241	248	195	198	277	302
Other International:						
United Kingdom	115	115	78	75	220	242
Denmark	63	68	41	44	132	146
Argentina	47	47	39	38	50	54
Canada	36	47	35	46	5	6

Colombia	30	29			178	174
Trinidad and Tobago	29	29			174	174
Norway	6	6	6	6	1	1
Netherlands	4	4	3	3	5	7
Venezuela[2]		7		3		21
Total Other International	330	352	202	215	765	825
Total International	1,601	1,582	1,084	1,092	3,100	2,940
Total Consolidated Operations	2,344	2,345	1,544	1,554	4,799	4,750
Equity Affiliates[3]	248	213	212	178	220	206
Total Including Affiliates[4,5]	2,592	2,558	1,756	1,732	5,019	4,956

[1] Located between Saudi Arabia and Kuwait.

[2] Through September 2006, LL-652 was reported as part of Venezuela consolidated operations. As of October 2006, LL-652 is reported under Equity Affiliates. See footnote 3 below.

[3] Equity Affiliates represent Chevron s share of production by affiliates, including Tengizchevroil (TCO) in Kazakhstan and Hamaca in Venezuela. Effective October 2006, the company converted its interests in Boscan and LL-652 operating service agreements in Venezuela to Empresas Mixtas (i.e., joint stock contractual structures), and these interests are accounted for as equity affiliates. LL-652 was previously reported as part of Venezuela consolidated operations, and Boscan was included in other produced volumes. See footnote 5 below.

[4] Includes natural gas consumed in operations of 498 million and 475 million cubic feet per day in 2007 and 2006, respectively.

[5] Does not include other produced volumes:

Athabasca Oil Sands net	27	27	27	27
Boscan Operating Service Agreement[3]		82		82
		5		

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As shown in the table on page 5, worldwide oil-equivalent production of 2.59 million barrels per day in 2007 was up 34,000 barrels per day from the prior year. Worldwide oil-equivalent production including other produced volumes (refer to footnote 5 to the table on page 5) was 2.62 million barrels per day, down about 2 percent from 2006. The decline was mostly attributable to the change in the Boscan operating service agreement in Venezuela to a joint-stock company in October 2006. Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of the factors explaining the 2005 2007 changes in production for crude oil and natural gas liquids and natural gas.

The company estimates that its average worldwide oil-equivalent production in 2008 will be approximately 2.65 million barrels per day. This estimate is subject to many uncertainties, including quotas that may be imposed by OPEC, the price effect on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, changes in fiscal terms or restrictions on the scope of company operations, delays in project start-ups, and production that may have to be shut in due to weather conditions, civil unrest, changing geopolitics or other disruptions to operations. Future production levels also are 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 oil and gas development projects.

Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-66 for data about the company s average sales price per barrel of crude oil and natural gas liquids and per thousand cubic feet of natural gas produced and the average production cost per oil-equivalent barrel for 2007, 2006 and 2005.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2007 for the company and its affiliates:

Productive Oil and Gas Wells[1] at December 31, 2007

	Productive[2] Oil Wells		Productive[2] Gas Wells	
	Gross	**Net**	**Gross**	**Net**
United States:				
California	25,029	23,305	176	44
Gulf of Mexico	1,600	1,375	1,104	893
Other U.S.	23,628	8,537	10,929	5,106
Total United States	50,257	33,217	12,209	6,043
Africa	2,190	748	8	3
Asia-Pacific	2,405	1,139	2,308	1,451
Indonesia	8,150	7,991	211	170
Other International	1,042	660	256	106
Total International	13,787	10,538	2,783	1,730
Total Consolidated Companies	64,044	43,755	14,992	7,773

Equity in Affiliates	1,072	375		
Total Including Affiliates	65,116	44,130	14,992	7,773
Multiple completion wells included above:	967	587	456	340

[1] Includes wells producing or capable of producing and injection wells temporarily functioning as producing wells. Wells that produce both oil and 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.

Reserves

Table V, beginning on page FS-66, provides a tabulation of the company s proved net oil and gas reserves, by geographic area, as of each year-end 2004 through 2007, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period. During 2007, the company provided oil and gas reserves estimates

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for 2006 to the Department of Energy, Energy Information Administration (EIA), that agree with the 2006 reserve volumes in Table V. This reporting fulfilled the requirement that such estimates are to be consistent with, and do not differ more than 5 percent from, the information furnished to the Securities and Exchange Commission in the company s 2006 Annual Report on Form 10-K. During 2008, the company will file estimates of oil and gas reserves with the Department of Energy, EIA, consistent with the 2007 reserve data reported in Table V.

The net proved-reserve balances at the end of each of the three years 2005 through 2007 are shown in the table below:

Net Proved Reserves at December 31

	2007	**2006**	**2005**
Liquids* Millions of barrels			
Consolidated Companies	4,665	5,294	5,626
Affiliated Companies	2,422	2,512	2,374
Natural Gas Billions of cubic feet			
Consolidated Companies	19,137	19,910	20,466
Affiliated Companies	3,003	2,974	2,968
Total Oil-Equivalent Millions of barrels			
Consolidated Companies	7,855	8,612	9,037
Affiliated Companies	2,922	3,008	2,869

* Crude oil, condensate and natural gas liquids

Acreage

At December 31, 2007, the company owned or had under lease or similar agreements undeveloped and developed oil and gas properties located throughout the world. The geographical distribution of the company s acreage is shown in the following table.

Acreage[1] at December 31, 2007
(Thousands of Acres)

	Undeveloped[2]		**Developed[2]**		**Developed and Undeveloped**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States:						
California	139	122	185	178	324	300
Gulf of Mexico	2,482	1,828	1,621	1,178	4,103	3,006
Other U.S.	3,800	3,012	5,884	2,588	9,684	5,600
Total United States	6,421	4,962	7,690	3,944	14,111	8,906
Africa	17,391	7,619	2,520	922	19,911	8,541
Asia-Pacific	52,006	23,660	5,847	2,630	57,853	26,290
Indonesia	9,109	5,894	382	340	9,491	6,234

Other International	35,688	20,022	2,397	664	38,085	20,686
Total International	114,194	57,195	11,146	4,556	125,340	61,751
Total Consolidated Companies	120,615	62,157	18,836	8,500	139,451	70,657
Equity in Affiliates	647	302	252	103	899	405
Total Including Affiliates	121,262	62,459	19,088	8,603	140,350	71,062

[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] 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 undeveloped proved reserves. The gross undeveloped acres that will expire in 2008, 2009 and 2010 if production is not established by certain required dates are 7,770, 10,860 and 4,288, respectively.

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Contract Obligations

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.

In the United States, the company is contractually committed to deliver to third parties and affiliates approximately 456 billion cubic feet of natural gas through 2010. The company believes it can satisfy these contracts from quantities available from production of the company s proved developed U.S. reserves. These contracts include variable-pricing terms.

Outside the United States, the company is contractually committed to deliver to third parties a total of approximately 631 billion cubic feet of natural gas from 2008 through 2010 from Argentina, Australia, Canada, Colombia, Denmark and the Philippines. 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 and in some cases consider inflation or other factors. The company believes it can satisfy these contracts from quantities available from production of the company s proved developed reserves in Argentina, Australia, Colombia, Denmark and the Philippines. The company plans to meet its Canadian contractual delivery commitments of 30 billion cubic feet through third-party purchases.

Development Activities

Details of the company s development expenditures and costs of proved property acquisitions for 2007, 2006 and 2005 are presented in Table I on page FS-61.

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, 2007. 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 12/31/07[3]		Net Wells Completed[1,2]					
			2007		2006		2005	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States:								
California	5	1	620		600		661	
Gulf of Mexico	39	18	30	1	34	5	29	3
Other U.S.	11	10	225	4	317	6	256	4
Total United States	55	29	875	5	951	11	946	7
Africa	8	3	43		45	2	38	
Asia-Pacific	13	4	223		235	1	150	

Indonesia			374		258		107	
Other International	4		52		43		79	
Total International	25	7	692		581	3	374	
Total Consolidated Companies	80	36	1,567	5	1,532	14	1,320	7
Equity in Affiliates			3		13		23	
Total Including Affiliates	80	36	1,570	5	1,545	14	1,343	7

[1] 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.

[2] Includes completion of wells beginning August 2005 related to the former Unocal operations.

[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 2007. 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.

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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, 2007. 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 12/31/07[3]		**Net Wells Completed[1,2]**					
			2007		**2006**		**2005**	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States:								
California								
Gulf of Mexico	12	5	4	7	9	8	14	8
Other U.S.				1	7		5	6
Total United States	12	5	4	8	16	8	19	14
Africa	35	15	6	2	1		4	1
Asia-Pacific	1	1	14	10	18	7	10	
Indonesia			1		2		5	
Other International	3	1	5	2	6	3	7	4
Total International	39	17	26	14	27	10	26	5
Total Consolidated Companies	51	22	30	22	43	18	45	19
Equity in Affiliates			41		1		8	
Total Including Affiliates	51	22	71	22	44	18	53	19

1 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.

2 Includes completion of wells beginning August 2005 related to the former Unocal operations.

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 2007. Does not include wells for which drilling was completed at year-end 2007 and that were reported

as suspended wells in Note 19 beginning on page FS-47. 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.

Details of the company s exploration expenditures and costs of unproved property acquisitions for 2007, 2006 and 2005 are presented in Table I on page FS-61.

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron s 2007 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-23.

The discussion that follows references the status of proved reserves recognition for significant long-lead-time projects not yet on production and for projects recently placed on production. Reserves are not discussed for recent discoveries that have yet to advance 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. In addition to the activities discussed, Chevron was active in other geographic areas, but those activities are considered less significant.

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Consolidated Operations

Chevron has production and exploration 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 natural gas equity resource base while growing a high-impact global gas business. The map on the left indicates Chevron s primary areas of production and exploration as well as the potential target markets for the company s natural gas resources.

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 during 2007 was 743,000 barrels per day, composed of 460,000 barrels of crude oil and natural gas liquids and 1.7 billion cubic feet of natural gas. Refer to Table V beginning on page FS-66 for a discussion of the net proved reserves and different hydrocarbon characteristics for the company s major U.S. producing areas.

California: The company has significant production in the San Joaquin Valley. In 2007, average net oil-equivalent production was 221,000 barrels per day, composed of 200,000 barrels of crude oil, 97 million cubic feet of natural gas and 5,000 barrels of natural gas liquids. Approximately 80 percent of the crude-oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

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Gulf of Mexico: Average net oil-equivalent production during 2007 for the company s combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region was 214,000 barrels per day. The daily oil-equivalent production comprised 105,000 barrels of crude oil, 576 million cubic feet of natural gas and 13,000 barrels of natural gas liquids.

During 2007, Chevron was engaged in various development and exploration activities in the deepwater Gulf of Mexico. Development work continued at the 58 percent-owned and operated Tahiti Field, where production start-up is expected in the third quarter 2009. Construction of the spar hull and topsides was completed in 2007; however, installation of the spar hull was delayed for about one year when testing revealed a metallurgical problem with the mooring shackles. Six development wells were drilled in 2007, and flow-back tests for five of the six were completed during the year. Initial booking of proved undeveloped reserves occurred in 2003, and the transfer of these reserves into the proved developed category is anticipated near the time of production start-up. With an estimated production life of 30 years, Tahiti is designed to have a maximum total daily production of 125,000 barrels of crude oil and 70 million cubic feet of natural gas. The total cost for this project is estimated at $4.7 billion and includes a planned second phase of field development after start-up that involves additional wells and facility upgrades.

Also under development is the 75 percent-owned and operated Blind Faith discovery, in which the company increased its ownership from 63 percent in July 2007. Three development wells were drilled, and construction of the topsides and hull was completed in 2007. The project includes a subsea development plan, with tieback to a semisubmersible floating production facility that had an original daily-production design capacity of 45,000 barrels of crude oil and 45 million cubic feet of natural gas based on the initial three-well development program. A fourth development well and associated facility upgrades are planned to commence in the first half of 2008. The facility upgrades are planned to increase the daily capacity to 60,000 barrels of crude oil and 60 million cubic feet of natural gas. Initial daily total production, including the fourth well, is estimated at 45,000 to 60,000 barrels of crude oil and 45 million to 60 million cubic feet of natural gas. Proved undeveloped reserves for the project were recognized in 2005. Reclassification of the reserves to the proved developed category is anticipated near the time of production start-up in the second quarter 2008. The estimated production life of the field is approximately 20 years.

The company is also participating in the ultra-deep Perdido Regional Development. The project encompasses the installation of a producing host facility to service multiple fields, including Chevron s 33 percent-owned Great White, 60 percent-owned Silvertip and 58 percent-owned Tobago. Chevron has a 38 percent interest in the Perdido Regional Host. All of these fields and the production facility are partner-operated. Activities during 2007 included facility construction and development drilling. First oil is expected in 2010, with the facility capable of handling 130,000 barrels of oil-equivalent per day. Proved undeveloped reserves related to the project were first recorded in 2006, and the phased reclassification of these reserves to the proved developed category is anticipated near the time of production start-up. The project has an expected life of approximately 25 years.

Deepwater exploration activities in 2007 included participation in 12 exploratory wells six wildcat and six appraisal. Exploratory work included the following:

Big Foot 60 percent-owned and operated. A successful appraisal well was completed in January 2008.

Jack 50 percent-owned and operated. A second appraisal well is scheduled for completion in the second quarter 2008.

Saint Malo 41 percent-owned and operated. Located near the Jack discovery, a second appraisal well drilled in 2007 is scheduled for completion by the end of the first quarter 2008.

Tubular Bells 30 percent-owned and nonoperated working interest. The second appraisal well began drilling in 2007 and is scheduled for completion in the first quarter 2008.

Knotty Head 25 percent-owned and nonoperated working interest. Discovered in 2005, subsurface studies were in progress in early 2008.

Puma 22 percent-owned and nonoperated working interest. Two appraisal wells were drilled in 2007.

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West Tonga 21 percent-owned and nonoperated working interest. A successful discovery well was drilled in 2007.

At the end of 2007, the company had not yet recognized proved reserves for any of the exploration projects discussed above.

Besides the activities connected with the development and exploration projects in the Gulf of Mexico area, Chevron also continued the federal, state and local permitting process during 2007 and early 2008 for a proposed natural gas import terminal at Casotte Landing in Jackson County, Mississippi. In February 2007, the company received approval from the Federal Energy Regulatory Commission for the proposed terminal. The terminal would be located adjacent to the company s Pascagoula Refinery and designed to process imported liquefied natural gas (LNG) for distribution to industrial, commercial and residential customers in Mississippi, Florida and the Northeast. The terminal would have an initial natural gas processing capacity of 1.3 billion cubic feet per day. The decision to construct a facility will be timed to align with the company s LNG supply projects.

The company also has contractual rights to 1 billion cubic feet per day of regasification capacity beginning in 2009 at the third party-owned Sabine Pass LNG terminal that is expected to be commissioned in the second quarter 2008. Also in the Sabine Pass area in Louisiana, the company has a binding agreement to be one of the anchor shippers in a 3.2 billion-cubic-foot-per-day third party-owned natural gas pipeline. Chevron will have 1.6 billion cubic feet per day of capacity in the pipeline, of which 1 billion cubic feet per day is in a new pipeline and 600 million cubic feet per day is interconnecting capacity to an existing pipeline. The new pipeline system will provide access to Chevron s Sabine and Bridgeline pipelines, which connect to the Henry Hub. The Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX) and is located on the natural gas pipeline system in Louisiana. Henry Hub interconnects to nine interstate and four intrastate pipelines.

Other U.S. Areas: Outside California and the Gulf of Mexico, the company manages operations across the mid-continental United States and Alaska. During 2007 in the Piceance Basin of northwestern Colorado, the company commenced development drilling in the basin s tight-gas formation. Facilities to produce 50 million cubic feet of natural gas per day are expected to start up in 2009. The Piceance project, in which the company holds a 100 percent operated working interest, is scalable, and the work is planned to be completed in multiple phases over the 15- to 20-year project life. The plans include expanding facilities to a production capacity of 450 million cubic feet per day. The total cost for this project is estimated at $7.3 billion. Also during 2007, Chevron initiated redevelopment programs in three offshore fields in Alaska s Cook Inlet, where the company operates 10 offshore platforms and five producing natural gas fields. The company also owns nonoperated working interest production and exploratory acreage at the White Hills prospect on the North Slope of Alaska. During 2007, the company s production outside California and the Gulf of Mexico averaged 308,000 net oil-equivalent barrels per day, composed of 104,000 barrels of crude oil, 1 billion cubic feet of natural gas and 33,000 barrels of natural gas liquids.

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b) Africa

Angola: Chevron holds company-operated working interests in Blocks 0 and 14 and nonoperated working interests in Block 2 and the Fina Sonangol Texaco (FST) area. In 2007, daily net production was 179,000 barrels of oil-equivalent.

The 39 percent-owned Block 0 and 31 percent-owned Block 14 are off the west coast, north of the Congo River. In Block 0, the company operates in two areas A and B composed of 21 fields that produced 120,000 barrels per day of net liquids in 2007. The Block 0 concession extends through 2030.

Area A of Block 0 comprises 15 producing fields and averaged daily net production of approximately 65,000 barrels of crude oil and 1,000 barrels of liquefied petroleum gas (LPG) in 2007. This production includes volumes from the Banzala Field that produced first oil in June 2007. The development of the Mafumeira Field in Area A continued in 2007 and will target the northern portion of the field. Initial booking of proved undeveloped reserves for this development occurred in 2003, and reclassification of proved undeveloped reserves into the proved developed category is anticipated near the time of first production expected in 2009. Maximum total daily production is expected to be approximately 30,000 barrels of crude oil in 2011.

Also in Area A, construction continued during 2007 on the Takula Gas Processing Platform and on projects for the Cabinda Gas Plant and the Flare and Relief Modification. These three projects, called the Area A Gas Management projects, are scheduled to start up in 2009 and are expected to eliminate the routine flaring of natural gas by reinjecting excess natural gas into various reservoirs.

In Area B of Block 0, average daily net production in 2007 from six producing fields was 47,000 barrels of crude oil and condensate and 7,000 barrels of LPG. Included in this production were volumes from the Sanha condensate natural gas utilization and Bomboco crude oil project that was completed in mid-2007. During 2007, a portion of the proved undeveloped reserves for this project was reclassified to the proved developed category.

In Block 14, net production in 2007 from the Benguela, Belize, Lobito, Tomboco, Kuito and Landana fields averaged 48,000 barrels of liquids per day. During 2007, development of the Benguela Belize-Lobito Tomboco (BBLT) project continued, with production of first oil at the Benguela and Tomboco fields. Further development drilling is expected to continue at all BBLT fields. Maximum total production for BBLT is estimated at 200,000 barrels of crude oil per day and is scheduled to occur in late 2008 or early 2009. Proved undeveloped reserves for Benguela and Belize were initially recognized in 1998 and for Lobito and Tomboco in 2000. Proved developed reserves for Belize and Lobito were recognized in 2006 and for Benguela and Tomboco in 2007. Additional BBLT reserves are expected to be reclassified to proved developed as project milestones are met. Development and production rights for these fields expire in 2027.

Another major project in Block 14 is the development of the Tombua and Landana fields. Construction of facilities continued in 2007. Production from the Landana North reservoir is utilizing the BBLT infrastructure. The maximum total daily production from Tombua and Landana of 100,000 barrels of crude oil is expected to occur in 2011. Proved undeveloped reserves were recognized for Tombua and Landana in 2001 and 2002, respectively. Initial reclassification from proved undeveloped to proved developed for Landana occurred in 2006 and continued in 2007. Further reclassification is expected between 2009 when the Tombua-Landana facilities are completed and 2012 when the drilling program is scheduled for completion. Development and production rights for these fields expire in 2028.

As of early 2008, the Negage project in Block 14 was under evaluation. Front-end engineering and design (FEED) for this project was expected to begin in late 2008, with the date of production start-up yet to be determined.

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Three exploration wells were drilled in Block 14 in 2007, one of which successfully appraised the 2006 Lucapa discovery. In the Malange Pinda prospect, one well resulted in a crude-oil discovery, and as of early 2008, evaluation was ongoing for the third well completed in the first quarter 2007. Appraisal drilling of the discoveries is expected to continue in 2008.

Chevron also has a 20 percent interest in a production-sharing contract (PSC) that covers Block 2, which is adjacent to the northwestern part of Angola s coast south of the Congo River, and a 16 percent interest in the onshore FST area. Combined net production from these properties in 2007 was 3,000 barrels of liquids per day.

Refer also to page 23 for a discussion of affiliate operations in Angola.

Democratic Republic of the Congo: Chevron has an 18 percent nonoperated working interest in a concession for offshore properties. Daily net production from seven fields averaged 3,000 barrels of oil-equivalent in 2007.

Republic of the Congo: Chevron has a 32 percent nonoperated working interest in the Nkossa, Nsoko and Moho-Bilondo exploitation permits and a 29 percent nonoperated working interest in the Kitina and Sounda exploitation permits, all of which are offshore. Net production from the Republic of the Congo fields averaged 8,000 barrels of oil-equivalent per day in 2007. The Moho-Bilondo development continued in 2007, with first production expected in the second half 2008. The development plan calls for crude oil produced by subsea well clusters to flow into a floating processing unit. Maximum total daily production of 90,000 barrels of crude oil is expected in 2010. Proved undeveloped reserves were initially recognized in 2001. Transfer to the proved developed category is expected near the time of first production. Chevron s development and production rights for Moho-Bilondo expire in 2030.

Two exploration wells were drilled in the Moho-Bilondo permit area during 2007 and were determined to have oil accumulations. As of early 2008, results continued under evaluation.

Angola-Republic of the Congo Joint Development Area: Chevron is the operator and holds a 31 percent interest in the Lianzi Development Area (formerly referenced as the 14K/A-IMI Unitization Zone), located in a joint development area shared equally between Angola and Republic of the Congo. In 2006, the development of the Lianzi area was approved by the committee of representatives from the two countries, and a conceptual field development plan was also submitted to this committee. In early 2007, one additional exploration well was drilled in the Lianzi area, but the results were considered subcommercial. As of early 2008, development studies and planning continued for this area.

Chad/Cameroon: Chevron is a nonoperating partner 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 a 21 percent interest in two affiliates that own the pipeline. Average daily net production from six fields in 2007 was 32,000 barrels of oil-equivalent, including volumes from a satellite field development project in the Maikeri Field that produced first oil in July 2007. In late 2007, a development application was submitted for another satellite field, Timbre, in the Doba area. The Chad producing operations are conducted under a concession agreement that expires in 2030.

Libya: Chevron is the operator and holds a 100 percent interest in the onshore Block 177 exploration license. Evaluation of seismic data was completed in late 2007, and an exploratory drilling program is scheduled for 2008.

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Nigeria: Chevron holds a 40 percent interest in 13 concessions predominantly in the onshore and near-offshore regions of the Niger Delta and varying interests in deepwater offshore blocks. In the Niger Delta, the company operates under a joint-venture arrangement with the Nigerian National Petroleum Corporation (NNPC), which owns a 60 percent interest. In 2007, net oil- equivalent production from 32 fields averaged 129,000 barrels per day. The daily oil-equivalent rate comprised 126,000 barrels of liquids and 15 million cubic feet of natural gas.

In the Niger Delta, Chevron has a 40 percent operated interest in the South Offshore Water Injection Project (SOWIP), an enhanced crude-oil recovery project in Oil Mining License (OML) 90 aimed at increasing production through water injection, natural-gas lift and production debottlenecking in the Okan and Delta fields. The upgraded Delta South Water Injection Platform (DSWIP), which is part of SOWIP, began water injection in March 2007 at a total daily rate of 100,000 barrels. The total maximum daily water injection rate is expected to increase to 240,000 barrels in 2009 upon the laying of water injection pipelines. Crude-oil production at year-end 2007 was approximately 5,000 barrels per day, and maximum total production is expected to be 35,000 barrels per day in 2010. Initial recognition of proved reserves was made in 2005. Reclassification of additional proved undeveloped reserves to the developed category is expected to occur after the evaluation of the water injection performance. The estimated life of the project is 25 years.

During 2007, the company continued development activities of deepwater offshore projects. The 68 percent-owned and operated deepwater Agbami project in OML 127 and OML 128 is a subsea development with wells tied back to a floating production, storage and offloading (FPSO) vessel, which was delivered from South Korea in December 2007. Development drilling and completion operations started in 2006, and subsea installation of production equipment began in 2007. Maximum total daily production of 250,000 barrels of crude oil and natural gas liquids is anticipated within one year after start-up, which is expected by the third quarter 2008. The company initially recognized proved undeveloped reserves for Agbami in 2002. A portion of the proved undeveloped reserves is scheduled to be reclassified to proved developed in 2008 near production start-up. The expected field life is approximately 20 years. The total cost for this project is estimated at $5.4 billion.

The Aparo Field in OML 132 and OML 140 and the Bonga SW Field in OML 118 share a common geologic structure and are planned to be jointly developed. The geologic structure lies 70 miles offshore in 4,300 feet of water. A pre-unit agreement was executed between Chevron and the OML 118 partner group in 2006. Final terms for a unitization agreement are expected to be completed in mid-2008. In 2007, FEED and tendering of major contracts continued. Development will likely involve an FPSO vessel and subsea wells. Partners are expected to make the final investment decision in the second half 2008, with production start-up projected for 2012. Maximum total production of 150,000 barrels of crude oil per day is expected to be reached within one year of production start-up. The company recognized initial proved undeveloped reserves in 2006 for its approximate 20 percent nonoperated working interest in the unitized area. The expected production life of this project is 20 years.

The company holds a 30 percent nonoperated working interest in the Usan project, located offshore in OML 138 and designed to utilize an FPSO vessel. The company recognized proved undeveloped reserves in 2004. Production start-up is estimated for late 2011, before which time a portion of proved undeveloped reserves is expected to be reclassified to the proved developed category. Maximum total production of 180,000 barrels of crude oil per day is expected to be achieved within one year of start-up. The end date of the concession period will be determined after final regulatory approvals are obtained.

Chevron operates and holds a 95 percent interest in the Nsiko discovery on OML 140. As of early 2008, subsurface evaluations and field development planning were ongoing. An investment decision is contingent on negotiations concerning the level of Nigerian content in the project s contracts.

The company has a 46 percent nonoperated interest in the Nnwa Field in OML 129, which contains a discovery that extends into two adjacent blocks not owned by Chevron. Commerciality is dependent upon resolution of the Nigerian Deepwater Gas fiscal regime and collaboration agreements with the adjacent blocks. A joint study was initiated in 2007 with owners in adjoining block OML 135 to progress technical and commercial evaluations.

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Chevron participated in two deepwater exploration wells during 2007. The Uge 2 well, drilled as an appraisal well to the Uge 1 discovery in Oil Prospecting License (OPL) 214, confirmed hydrocarbons. The company has a 20 percent nonoperated working interest in OPL 214. The second well was deemed noncommercial. Two additional deepwater exploration wells are planned in 2008.

Chevron also is involved in projects in the Niger Delta region that support the company s strategic initiative to commercialize its significant natural gas resource base outside the United States. Construction is under way on the Phase 3A expansion of the Escravos Gas Plant (EGP), which is expected to start up in 2009. Phase 3A scope includes offshore natural gas gathering and compression infrastructure and a second gas processing facility, which potentially would increase processing capacity from 285 million to 680 million cubic feet of natural gas per day and increase LPG and condensate export capacity from 12,000 to 47,000 barrels per day. EGP Phase 3A is designed to process natural gas from the Meji, Delta South, Okan and Mefa producing fields. Proved undeveloped reserves associated with EGP Phase 3A were recognized in 2002. These reserves are expected to be reclassified to proved developed as various project milestones are reached and related projects are completed. The anticipated life of the project is 25 years. Chevron holds a 40 percent operated interest in this project.

Refer also to page 26 for a discussion of the planned gas-to-liquids facility at Escravos.

Chevron holds a 37 percent interest in the West African Gas Pipeline, which is designed to supply Nigerian natural gas to customers in Ghana, Benin and Togo for industrial applications and power generation. First gas is anticipated to be shipped by mid-2008, and facility completion, with a capacity of 170 million cubic feet of natural gas per day, is expected in the second-half 2008. Chevron is the managing sponsor in the West African Pipeline Company Limited affiliate, which constructed, owns and operates the 412-mile pipeline.

In March 2007, Chevron signed a shareholders agreement for a 19 percent interest in the OKLNG Free Zone Enterprise (OKLNG) affiliate, which will operate the Olokola LNG project. OKLNG plans to build a multitrain, 22 million-metric-ton-per-year natural gas liquefaction facility and marine terminal located in a free trade zone. The project entered FEED in 2006 and is expected to be implemented in phases, commencing with two trains having at least 11 million-metric-ton-per-year total capacity. Approximately 50 percent of the gas supplied to the plant is expected to be provided from the producing areas associated with Chevron s joint-venture arrangement with NNPC (discussed earlier in this section).

Nigeria-São Tomé e Príncipe Joint Development Zone (JDZ): Chevron holds a 46 percent operated interest in JDZ Block 1. In 2006, the first exploration well encountered hydrocarbons. In 2008, technical studies are planned to determine the need for additional drilling and evaluate development alternatives.

c) Asia-Pacific

Australia: During 2007, the average net oil-equivalent production from Chevron s interests in Australia was 100,000 barrels per day, composed of 39,000 barrels of liquids and 372 million cubic feet of natural gas.

Chevron has a 17 percent nonoperated working interest in the North West Shelf (NWS) Venture offshore Western Australia. Daily net production from the project during 2007 averaged 29,000 barrels of crude oil and condensate, 369 million cubic feet of natural gas, and 5,000 barrels of LPG. Approximately

75 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. A fifth LNG train, which is intended to increase export capacity by more than 4 million metric tons per year, to more than 16 million, is expected to be commissioned in late 2008. The Angel natural gas field, where development is under way, and the North Rankin Redevelopment project will supply the fifth LNG train. Start-up of the fifth train is projected to accelerate production from the NWS fields. An investment decision by the company and its partners on the North Rankin Redevelopment project is expected in late 2008. The end of the NWS Venture concession period is 2034.

On Barrow and Thevenard islands off the northwest coast of Australia, Chevron operates crude oil producing facilities that had combined net production of 5,000 barrels per day in 2007. Chevron s interests in these operations are 57 percent for Barrow and 51 percent for Thevenard.

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Also off the northwest coast of Australia, Chevron is the operator of the Gorgon development and has a 50 percent ownership interest across most of the Greater Gorgon Area. Chevron and its two joint-venture participants signed a Framework Agreement in 2005 that will enable the combined development of Gorgon and the nearby natural gas fields as one world-scale project. In 2007, the company received environmental regulatory approvals necessary for the development of the Greater Gorgon LNG project on Barrow Island using a two-train, 10 million-metric-ton-per-year LNG development plan. As of early 2008, the detailed environmental conditions were incorporated into the project s updated optimization and engineering efforts for a three-train, 15 million-metric-ton-per-year LNG configuration, and activities to secure the necessary government approvals were under way. Natural gas for the project will be supplied from the Gorgon and Jansz fields. The Gorgon project has an expected economic life of at least 40 years.

Elsewhere in the Greater Gorgon Area during 2007, Chevron participated in four successful appraisal wells two in the Browse Basin and two in the Carnarvon Basin. Chevron also participated in two exploration wells in the Carnarvon Basin, with Lady Nora resulting in a natural gas discovery and Snarf-1 expecting to be completed in 2008. As of early 2008, plans were also being developed to appraise the 67 percent-owned Clio and the 50 percent-owned Chandon natural gas discoveries. Concept studies continued in 2007 on the Wheatstone natural gas discovery, and a successful appraisal well was drilled late in the year. Further appraisal wells are planned to be drilled in the area in 2008.

At the end of 2007, the company had not recognized proved reserves for any of the Greater Gorgon Area fields. Recognition is contingent on securing sufficient LNG sales agreements and achieving other key project milestones. In 2007, the company signed a nonbinding Heads of Agreement (HOA) with GS Caltex, a Chevron affiliated company, to supply 250,000 metric tons of LNG annually from the Gorgon project. Combined with the nonbinding HOAs signed previously with three utility customers in Japan, volumes under the four HOAs totaled 4.5 million metric tons per year. As of early 2008, negotiations were continuing to finalize binding sales agreements on these HOAs. Purchases by each of these customers are expected to range from 300,000 metric tons per year to 1.5 million metric tons per year over 25 years.

Azerbaijan: Chevron holds a 10 percent nonoperated working interest in the Azerbaijan International Operating Company (AIOC), which produces crude oil in the Caspian Sea from the Azeri-Chirag-Gunashli (ACG) project. Chevron also has a 9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate, which transports AIOC production by pipeline from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities in Ceyhan, Turkey. (Refer to Pipelines under Transportation Operations on page 28 for a discussion of the BTC operations.)

In 2007, the company s daily net production from AIOC averaged 61,000 barrels of oil-equivalent. First production from Phase III of ACG development is targeted for the second quarter 2008. Total crude-oil production from the ACG project is expected to increase to about 940,000 barrels per day by the end of 2008 and to more than 1 million barrels per day in 2009. Proved undeveloped reserves for ACG are expected to be reclassified to proved developed reserves as wells are drilled and completed. The AIOC operations are conducted under a 30-year PSC that expires in 2024.

Kazakhstan: Chevron holds a 20 percent nonoperated working interest in the Karachaganak project that is being developed in phases. During 2007, Karachaganak net oil-equivalent production averaged 66,000 barrels per day, composed of 41,000 barrels of liquids and 149 million cubic feet of natural gas. In 2007, access to the Caspian Pipeline Consortium (CPC) and Atyrau-Samara (Russia) pipelines allowed Karachaganak sales of approximately 166,000 barrels per day (31,000 net barrels) of processed liquids at prices available in world markets. The remaining liquids were sold into Russian markets. During 2007, work continued on a fourth train that is designed to increase this export of processed liquids by 56,000 barrels per day (11,000 net barrels). The fourth train is expected to start up in 2009.

In 2007, the Karachaganak operator signed a 15-year natural gas sales agreement to deliver up to 1.6 billion cubic feet per day of sour gas to a Russian-Kazakh joint venture. Deliveries under the agreement commenced in September 2007. As of early 2008, Phase III development of Karachaganak continued under evaluation. The project could increase maximum total production to 335,000 barrels of liquids per day and 1.7 billion cubic feet of natural gas per day. Timing for the recognition of Phase III proved reserves is uncertain and depends on finalizing a viable Phase III project design.

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Project start-up is anticipated in 2012 or after, depending on achievement of project milestones. Karachaganak operations are conducted under a 40-year PSC that expires in 2038.

Refer also to pages 23 and 24 for a discussion of Tengizchevroil, a 50 percent-owned affiliate with operations in Kazakhstan.

Russia: Refer to page 24 for a discussion of the company s interest in a Russian joint venture.

Bangladesh: Chevron is the operator of three onshore blocks, with a 98 percent interest in Blocks 12, 13 and 14 and operator of Block 7, in which the company holds a 43 percent interest. Net oil-equivalent production in 2007 averaged 47,000 barrels per day, composed of 275 million cubic feet of natural gas and 2,000 barrels of liquids. Production from the Bibiyana Field in Block 12 started in March 2007. The project is expected to reach maximum total production of 500 million cubic feet per day by late 2010. The development program included a gas processing plant with capacity of 600 million cubic feet per day and a natural gas pipeline. Initial proved reserves were recognized in 2005. In 2007, additional proved reserves were recognized based on development wells drilled during the year, and a portion of proved undeveloped reserves were reclassified to the proved developed category. Bibiyana operations are conducted under a PSC that expires in 2034.

Cambodia: Chevron operates and holds a 55 percent interest in the 1.2 million-acre Block A, located offshore in the Gulf of Thailand. A four-well exploration and appraisal program was completed in 2007. As of early 2008, the results and prospects for further drilling were being evaluated.

Myanmar: Chevron has a 28 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 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 (PTT). The company s average net natural gas production in 2007 was 100 million cubic feet per day, or 17,000 barrels of oil-equivalent.

Thailand: Chevron has operated and nonoperated working interests in several different offshore blocks. The company s net oil-equivalent production in 2007 averaged 224,000 barrels per day, composed of 71,000 barrels of crude oil and condensate and 916 million cubic feet of natural gas. All of the company s natural gas production is sold to PTT under long-term sales contracts.

Operated interests are in Pattani and other fields with ownership interests ranging from 35 percent to 80 percent in Blocks 10 through 13, B12/27, B8/32, 9A, G4/43 and G4/48. Blocks B8/32 and 9A produce crude oil and natural gas from six operating areas, and Blocks 10 through 13 and B12/27 produce crude oil, condensate and natural gas from 16 operating areas.

The company s production of natural gas increased beginning in March 2007 with PTT s commissioning of a third natural gas pipeline. In October 2007, the leases for Blocks 10 through 13 were extended from 2012 to 2022. In December 2007, the company signed a natural gas sales agreement that will increase daily contract quantity of natural gas from these blocks by 500 million cubic feet, to 1.2 billion, by 2012. In addition, this agreement is expected to enable the construction of a second central natural gas processing facility in the Platong area. The 70 percent-owned

Platong Gas II project is designed to add 420 million cubic feet per day of processing capacity in the first quarter 2011. The company expects to recognize proved reserves throughout the project s 12-year life as the wellhead platforms are installed.

Chevron has a 16 percent nonoperated working interest in Blocks 14A, 15A, 16A, G9/48 and G8/50, known collectively as the Arthit Field. First production from Arthit is planned for the second quarter 2008 and is expected to reach an estimated maximum total production of 330 million cubic feet of natural gas per day by the end of 2008. Proved undeveloped reserves were recorded for the first time in 2006. Reclassification of proved undeveloped reserves to the proved developed category is anticipated in 2008, near production start-up. The concessions that cover Arthit operations expire in 2040.

In G9/48, one exploration well is required to be drilled by the first quarter 2009. Chevron also holds exploration interests in a number of blocks that are currently inactive, pending resolution of border issues between Thailand and Cambodia.

In late 2007, the company was granted the concession rights to four prospective offshore petroleum blocks in Thailand, which includes Block G8/50 (discussed earlier in this section). Chevron s interest in the other three operated blocks, G4/50, G6/50 and G7/50, ranges from 35 percent to 75 percent.

Vietnam: The company is operator in two PSCs offshore southwest Vietnam in the northern part of the Malay Basin. Chevron has a 42 percent interest in one PSC that includes Blocks B and 48/95 and a 43 percent interest in the other PSC that has Block 52/97. Chevron also has a 50 percent operated interest in Block B122 offshore eastern Vietnam. No production occurred in these PSCs during 2007.

The Vietnam Gas Project is aimed at developing an area in the two Malay Basin PSCs to supply natural gas to state-owned PetroVietnam. In the third quarter 2007, PetroVietnam approved the revised development plan, joint development area and unitization agreement for the project. The project includes installation of wellhead and hub platforms, an FPSO vessel, infield pipelines and a central processing platform. The timing of first natural gas production is dependent upon the outcome of commercial negotiations. Maximum total production of approximately 500 million cubic feet of natural gas per day is projected within five years of start-up. Recognition of initial proved undeveloped reserves would follow execution of the gas sales agreements and project approval. The PSC for Blocks B and 48/95 and the PSC for Block 52/97 will expire in 2022 and 2029, respectively.

In Block 122, a planned seismic program was postponed in 2007 due to issues of territorial claim between Vietnam and China.

China: Chevron has nonoperated working interests of 33 percent in Blocks 16/08 and 16/19 located in the Pearl River Delta Mouth Basin, 25 percent in the QHD-32-6 Field in Bohai Bay and 16 percent in the unitized and producing BZ 25-1 Field in Bohai Bay Block 11/19. The company s net oil-equivalent production in China during 2007 averaged 26,000 barrels per day, composed of 22,000 barrels of crude oil and condensate and 22 million cubic feet of natural gas.

Joint development of the HZ25-3 and HZ25-1 crude-oil fields in Block 16/19 commenced in the first quarter 2007. First production is expected in early 2009, reaching a maximum total daily production of approximately 14,000 barrels of crude oil late in the year. Chevron also has interests ranging from 36 percent to 50 percent in four prospective onshore natural gas blocks in the Ordos Basin totaling about 1.5 million acres. In December 2007, the company signed a 30-year PSC that became effective in February 2008 for the development of the Chuandongbei natural gas area in the onshore Sichuan Basin. The aggregate design input capacity of the proposed gas plants is expected to be 740 million cubic feet of natural gas per day. The company holds a 49 percent interest in the area.

Partitioned Neutral Zone (PNZ): Chevron holds a 60-year concession that expires in 2009 to produce crude oil from onshore properties in PNZ, which is located between Saudi Arabia and Kuwait. Negotiations to extend the concession period were ongoing in early 2008. Net production in PNZ for 2007 represented 4 percent of Chevron s net barrels of oil-equivalent total.

Under the current concession, Chevron has the right to Saudi Arabia s 50 percent interest in the hydrocarbon resource and pays a royalty and other taxes on volumes produced. During 2007, average net oil-equivalent production was 112,000 barrels per day, composed of 109,000 barrels of crude oil and 17 million cubic feet of natural gas. The second phase of a steamflood pilot project is expected to be completed in early 2009. This pilot is a unique application of steam injection into a carbonate reservoir and, if successful, could significantly increase recoverability of the heavy oil in place.

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 2007 averaged 26,000 barrels per day, composed of 126 million cubic feet of natural gas and 5,000 barrels of condensate. Chevron also develops and produces steam resources under an agreement with the National Power Corporation, a Philippine government owned company. The combined generating capacity is 637 megawatts.

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d) Indonesia

Chevron s operated interests in Indonesia are managed by several wholly owned subsidiaries, including PT. Chevron Pacific Indonesia (CPI). CPI holds operated interests of 100 percent in the Rokan and Siak PSCs and 90 percent in the Mountain Front Kuantan PSC. Other subsidiaries operate four PSCs in the Kutei Basin, East Kalimantan and one PSC in the Tarakan Basin, Northeast Kalimantan. These interests range from 80 percent to 100 percent. Chevron also has nonoperated working interests in a joint venture in South Natuna Sea Block B and in the NE Madura III block in the East Java Sea Basin. Chevron s interests in these PSCs range from 25 percent to 40 percent. In January 2008, Chevron relinquished its 35 percent nonoperated working interest in the Donggala PSC in the Kutei Basin. In West Java, Chevron wholly owns a power generation company that operates the Darajat geothermal contract area in Garut, West Java, with a total capacity of 259 megawatts. This includes the Darajat III 110-megawatt unit that was placed online in July 2007. Chevron also operates a 95 percent-owned 300-megawatt cogeneration facility in support of CPI s operation in North Duri and the wholly owned Salak geothermal field, located in West Java, with a total capacity of 377 megawatts.

The company s net oil-equivalent production in 2007 from all of its interests in Indonesia averaged 241,000 barrels per day. The daily oil-equivalent rate comprised 195,000 barrels of crude oil and 277 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. An expansion area, Area 12, is targeted for start-up in late 2008. Maximum total daily production is estimated at 34,000 barrels of crude oil in 2012. Two other areas have been identified for possible sequential expansions. Proved undeveloped reserves for North Duri were recognized in previous years, and reclassification from proved undeveloped to proved developed is scheduled to occur during various stages of sequential completion. The Rokan PSC expires in 2021.

A drilling campaign continued through 2007 in South Natuna Sea Block B, with first oil produced from the Kerisi Field in December 2007. First production of LPG from the Belanak Field was achieved in April 2007. Additional development drilling in the North Belut Field is scheduled to begin in mid-2008, with first production expected in 2009.

In January 2007, Chevron combined the development of the Gendalo and Gehem deepwater natural gas fields located in the Kutei Basin into a single project with one development concept. In August 2007, the company submitted final development plans to the government of Indonesia. Approvals are expected during the first-half 2008. The Bangka natural gas project was under evaluation in 2007 and will likely be developed in parallel with Gendalo and Gehem. The development timing is partially dependent on government approvals, market conditions and the achievement of key project milestones. The company holds an 80 percent operated interest in these projects.

As of early 2008, the development concept for the 50 percent-owned and operated Sadewa project in the Kutei Basin remained under evaluation. Also in the Kutei Basin, the development of the Seturian Field project continued in 2007, with first production anticipated in late 2008. The project is designed to supply natural gas to a state-owned refinery.

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e) Other International Areas

Argentina: Chevron holds an operated interest in 17 concessions and one exploratory block in the Neuquen and Austral basins. Working interests range from 19 percent to 100 percent. Net oil-equivalent production in 2007 averaged 47,000 barrels per day, composed of 39,000 barrels of crude oil and 50 million cubic feet of natural gas. Chevron also holds a 14 percent interest in the Oleoductos del Valle S.A. pipeline.

In 2007, three exploratory wells were drilled in the Austral Basin, and two were successful.

Brazil: Chevron holds working interests ranging from 20 percent to 52 percent in three deepwater blocks. None of the blocks had production in 2007.

In Block BC-4, located in the Campos Basin, the company is the operator and has a 52 percent interest in the Frade Field. In 2007, major construction activities included work to convert a crude-oil tanker to an FPSO vessel and the manufacture of subsea systems and flowlines for the project. Subsea installation activities began in early 2008. Proved undeveloped reserves were recorded for the first time in 2005. Partial reclassification of proved undeveloped reserves to the proved developed category is anticipated upon production start-up in early 2009. Estimated maximum total production of 90,000 oil-equivalent barrels per day is anticipated in 2011. The concession that involves the Frade project expires in 2025.

The company concentrates its exploration efforts in the Campos and Santos basins. In the partner-operated Campos Basin Block BC-20, two areas 38 percent-owned Papa-Terra and 30 percent-owned Maromba have been retained for development following the end of the exploration phase of this block. In 2006, a Papa-Terra field development plan was submitted to the government, and as of early 2008 this plan was still under evaluation. In Maromba as of early 2008, a pilot production system was under consideration, with first oil projected for 2013. Elsewhere in Campos, the company relinquished its 30 percent nonoperated working interest in BM-C-4. In the 20 percent-owned and partner-operated Santos Basin Block BS-4, development options for the Atlanta and Oliva fields were under evaluation.

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. Daily net production averaged 178 million cubic feet of natural gas, or 30,000 barrels of oil-equivalent, in 2007. During the year, new dehydration facilities were constructed that enabled natural gas exports to Venezuela beginning in January 2008.

Trinidad and Tobago: The company has a 50 percent nonoperated working interest in four blocks in the East Coast Marine Area offshore Trinidad, which include the Dolphin and Dolphin Deep producing natural gas fields and the Starfish discovery. Net production from Dolphin and Dolphin Deep in 2007 averaged 174 million cubic feet of natural gas per day, or 29,000 barrels of oil-equivalent.

In May 2007, a domestic natural gas sales agreement was signed for the Trinidad Incremental Gas project. The agreement includes the delivery of 220 million cubic feet per day for 11 years with an option for a four-year extension. Drilling operations started in late 2007 at the Dolphin platform. First gas for the project is expected in 2009, ramping up to maximum total production of 220 million cubic feet of natural gas per day in early 2010. Reserves were initially booked in 2006. In 2007, additional proved reserves were recorded, and some proved undeveloped reserves were reclassified to the proved developed category. Further reclassifications are expected in 2008, following the drilling of additional development wells.

Chevron also holds a 50 percent operated interest in the Manatee area of Block 6d. In early 2007, an agreement was signed by the governments of Venezuela and Trinidad and Tobago to unitize the Loran Field in Venezuela and the Manatee area. Negotiations are expected to continue in 2008 to achieve a field-specific unitization treaty.

Venezuela: Chevron holds interest in two affiliates located in western Venezuela and one affiliate in the Orinoco Belt. The company also operates in two exploratory blocks offshore Plataforma Deltana, with working interests of 60 percent in Block 2 and 100 percent in Block 3. In Block 2, which includes the Loran natural gas field, a conceptual offshore development plan was completed in 2007. In Block 3, Chevron discovered natural gas in 2005 that is in close proximity to Loran. Both Block 3 and Loran will provide a possible supply source for Venezuela s first LNG train. Seismic work elsewhere in Block 3 was completed in 2007. Chevron also has a 100 percent interest in the Cardon III block, located north of the Maracaibo producing region. Seismic in this block, which has natural gas potential, was acquired in 2007 and is planned to be processed in 2008. Petróleos de Venezuela, S.A. (PDVSA) has the option to increase its ownership in all three company-operated blocks up to 35 percent upon declaration of commerciality.

Refer also to page 24 for a discussion of affiliate operations in Venezuela.

Canada: The company has nonoperated working interests of 27 percent in the Hibernia Field offshore eastern Canada and 20 percent in the Athabasca Oil Sands Project (AOSP), a 60 percent operated interest in the Ells River In Situ Oil Sands Project, a 28 percent operated interest in the Hebron project and exploration acreage in the Mackenzie Delta, Beaufort Sea and the Orphan Basin. Excluding volumes mined at the AOSP, average net oil-equivalent production during 2007 was 36,000 barrels per day, composed of 35,000 barrels of crude oil and natural gas liquids and 5 million cubic feet of natural gas. Substantially all of the production was from the Hibernia Field. At AOSP, bitumen mined and upgraded to synthetic crude oil averaged 27,000 net barrels per day.

At AOSP, the first phase of an expansion project, with an estimated total project cost of $10.2 billion, is being designed to upgrade an additional 100,000 barrels of bitumen into synthetic crude oil per day. The expansion would increase total AOSP design capacity to more than 255,000 barrels of bitumen per day in 2010. Preliminary work is under way to determine the feasibility of additional expansion projects.

The Ells River project consists of heavy oil leases of more than 85,000 acres. The area contains significant volumes with the potential for recovery using Steam Assisted Gravity Drainage, a proven technology that employs steam and horizontal drilling to extract the bitumen through wells rather than through mining operations. During 2007, a successful appraisal drilling program involving 66 wells was completed. Follow-up appraisal activities are planned in 2008, with a similar number of wells and a small 2-D and 3-D seismic program.

The potential development at Hebron stalled in 2006 after unsuccessful negotiations with the provincial government of Newfoundland and Labrador. In mid-2007, the Hebron partners executed a nonbinding memorandum of understanding with the government that outlined fiscal, equity and local-benefit terms associated with the Hebron project. Execution of formal agreements is expected during 2008.

Exploratory activities are expected to continue during 2008 in the Mackenzie Delta and the Orphan Basin.

Denmark: Chevron holds a 15 percent nonoperated working interest in the Danish Underground Consortium (DUC), which produces crude oil and natural gas from 15 fields in the Danish North Sea and has a 12 percent interest in each of four exploration licenses. Net oil-equivalent production in 2007 from DUC averaged 63,000 barrels per day, composed of 41,000 barrels of crude oil and 132 million cubic feet of natural gas.

Faroe Islands: Chevron has a 40 percent interest in five offshore blocks and is the operator. During 2007, the company acquired a 2-D seismic survey over License 008, located near the Rosebank/Lochnagar discovery in the United Kingdom.

Greenland: In October 2007, Chevron was awarded a 29 percent nonoperated working interest in an exploration license in Block 4 offshore West Greenland in the Baffin Basin. The planned four-year work program includes seismic acquisition, and geologic, engineering and environmental studies.

Netherlands: Chevron is the operator and holds interests ranging from 34 percent to 80 percent in nine blocks in the Dutch sector of the North Sea. The company s daily net production from eight producing fields averaged 3,000 barrels of crude oil and 5 million cubic feet of natural gas. Production start-up at the first stage of the A/B Gas Project from Block A12 occurred in December 2007 at an initial daily total rate of 60 million cubic feet of natural gas. As of early 2008, the second stage of the project was under evaluation.

Norway: At the 8 percent-owned and partner-operated Draugen Field, the company s net production during 2007 was 6,000 barrels of oil-equivalent per day. In the 40 percent-owned and partner-operated PL397, seismic survey data was processed in 2007. Acquisition of additional seismic data is planned for 2008. Exploration activities are expected to continue in 2008 in various license areas.

United Kingdom: The company s average net oil-equivalent production in 2007 from nine offshore fields was 115,000 barrels per day, composed of 78,000 barrels of crude oil and 220 million cubic feet of natural gas. Most of the

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production was from the 85 percent-owned and operated Captain Field and the 32 percent-owned and jointly-operated Britannia Field.

As of early 2008, development activities were continuing at the Britannia satellite fields Callanish and Brodgar, in which Chevron holds 17 percent and 25 percent nonoperated working interests, respectively. Production start-up from these two fields is expected to occur in late 2008. Together, these fields are expected to achieve maximum total daily production of 25,000 barrels of crude oil and 133 million cubic feet of natural gas several months after both fields start up. Proved undeveloped reserves were initially recognized in 2000. In 2006, proved undeveloped reserves were reclassified to the proved developed category. This project has an expected production life of approximately 15 years.

In exploration activities, the Alder discovery west of the Britannia Field was being evaluated in early 2008 and is likely to be developed as a tieback to existing infrastructure. The company has a 70 percent operated interest in the project, which is expected to start up and reach maximum total daily production rates of 9,000 barrels of crude oil and 80 million cubic feet of natural gas in 2012. The timing of the initial proved-reserves recognition was also under evaluation in early 2008. This project has an expected production life of approximately nine years.

At the Rosebank/Lochnagar discovery west of the Shetland Islands, an appraisal program consisting of three wells and a sidetrack was completed in 2007. All four wellbores encountered hydrocarbons, and an evaluation for commerciality was under way in early 2008. Evaluation continued of a successful natural gas production test at the Tormore well that is also in the West of Shetlands gas trend. During 2007, another successful appraisal well was drilled in the Clair Phase 2 area.

Equity Affiliate Operations

Angola: In addition to the exploration and producing activities in Angola, Chevron participates in the Angola LNG project, for which the company and partners made a final investment decision at the end of 2007. The LNG plant will be designed with a capacity to process 1 billion cubic feet of natural gas per day and will provide a commercial option for Angola s natural gas resources. Chevron has a 36 percent interest in the Angola LNG affiliate. Construction began in early 2008 on the 5.2 million-metric-ton-per-year onshore LNG plant that is located in the northern part of the country. Plant start-up is expected in 2012. At the end of 2007, the company made an initial booking of proved natural gas reserves for the producing operations associated with this LNG project. The life of the LNG plant is estimated to be in excess of 20 years.

Kazakhstan: The company holds a 50 percent interest in Tengizchevroil (TCO), which is developing the Tengiz and Korolev crude-oil fields located in western Kazakhstan under a 40-year concession that expires in 2033. Chevron s net oil-equivalent production in 2007 from these fields averaged 176,000 barrels per day, composed of 144,000 barrels of crude oil and natural gas liquids and 193 million cubic feet of natural gas.

TCO is undergoing a significant expansion composed of two integrated projects referred to as the Second Generation Plant (SGP) and Sour Gas Injection (SGI). At a total combined cost of approximately $7.2 billion, these projects are designed to increase TCO s crude-oil production capacity to 540,000 barrels per day during the second half of 2008.

SGP involves the construction of a large processing train for treating crude oil and the associated sour gas (i.e., high in sulfur content). The SGP design is based on the same conventional technology employed in the existing processing trains. Proved undeveloped reserves associated with SGP were recognized in 2001. Wells were drilled, deepened and/or completed since 2002 in the Tengiz and Korolev reservoirs to produce volumes required for the new SGP train. Reserves associated with the project were reclassified to the proved developed category. Over the next decade, ongoing field development is expected to result in the reclassification of additional proved undeveloped reserves to proved developed.

SGI involves taking a portion of the sour gas separated from the crude-oil production at the SGP processing train and reinjecting it into the Tengiz reservoir. Chevron expects that SGI will have two key effects. First, SGI will reduce the sour gas processing capacity required at SGP, thereby increasing liquid production capacity and lowering the quantities of sulfur and gas that would otherwise be generated. Second, SGI is expected over time to increase production efficiency and recoverable volumes as the injected gas maintains higher reservoir pressure and displaces oil toward producing wells. The company anticipates recognizing additional proved reserves associated with the SGI expansion in late 2008. The primary SGI risks include uncertainties about compressor performance associated with injecting high-pressure sour gas and subsurface responses to injection.

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Initial production from the first phase of the SGI/SGP expansion projects occurred in late 2007. This first phase increased production capacity by 90,000 barrels per day, to approximately 400,000, in January 2008.

As of early 2008, essentially all of TCO s production was being 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. Also in early 2008, CPC was seeking stockholder approval for an expansion to accommodate increased TCO volumes beginning in 2009. Expanded rail-car loading and rail-export facilities, designed to transport most of the incremental SGI/SGP production prior to the CPC expansion, started operation during 2007. As of early 2008, other alternatives were also being explored to increase export capacity.

Venezuela: Chevron has a 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela s Orinoco Belt, a 39 percent interest in the Petroboscan affiliate that operates the Boscan Field, and a 25 percent interest in the Petroindependiente affiliate that operates the LL-652 Field. The company s average net oil-equivalent production during 2007 from these affiliates was 72,000 barrels per day, composed of 68,000 barrels of crude oil and 27 million cubic feet of natural gas.

The Hamaca project has a total design capacity for processing and upgrading 190,000 barrels per day of heavy crude oil (8.5 degrees API gravity) into 180,000 barrels of lighter, higher-value crude oil (26 degrees API gravity). In February 2007, the president of Venezuela issued a decree announcing the government s intention for PDVSA to increase its ownership in all Orinoco Heavy Oil Associations effective May 1, 2007, including Chevron s 30 percent-owned Hamaca project, to a minimum of 60 percent. In December 2007, Chevron executed a conversion agreement and signed a charter and by-laws with a PDVSA subsidiary that provided for Chevron to retain its 30 percent interest in the Hamaca project. The new entity, Petropiar, commenced activities in January 2008.

The Boscan Field is located onshore western Venezuela. A 3-D seismic program was acquired in 2007 that is expected to guide future development activities in South Boscan. The water-injection pressure-maintenance project was expanded to include four wells converted to injectors in 2007, and four new injectors are planned to be drilled in 2008 and 2009. The LL-652 Field is located in Lake Maracaibo.

Russia: As of early 2008, Chevron and JSC Gazprom Neft continued to negotiate the final agreements for exploration and development activities in two licensed areas in the Yamal-Nenets region of western Siberia. Once the agreement is finalized, Chevron is expected to hold a 49 percent interest in the Northern Taiga Neftegaz LLC affiliate, which will operate in the licensed areas. Exploration and delineation activities are planned for 2008 on both licenses.

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. Outside the United States, substantially all of the natural gas sales are from the company s producing interests in Australia, Bangladesh, Kazakhstan, Indonesia, Latin America, the Philippines, Thailand and the United Kingdom. Substantially all of the company s natural gas liquids sales are from company operations in Africa, Australia and Indonesia. Refer to Selected Operating Data, on page FS-10 in Management s Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company s natural gas and natural gas liquids sales volumes. Refer also to Contract Obligations on page 8 for information related to the company s contractual commitments for the sale of crude oil and natural gas.

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Downstream Refining, Marketing and Transportation

Refining Operations

At the end of 2007, the company s refining system consisted of 19 fuel refineries and an asphalt plant. The company operated nine of these facilities, and 11 were operated by affiliated companies. The daily refinery inputs for 2005 through 2007 for the company and affiliate refineries are as follows:

Petroleum Refineries: Locations, Capacities and Inputs
(Capacities and inputs in thousands of barrels per day; includes equity share in affiliates)

Locations		December 31, 2007 Number	December 31, 2007 Operable Capacity	Refinery Inputs 2007	Refinery Inputs 2006	Refinery Inputs 2005
Pascagoula	Mississippi	1	330	285	337	263
El Segundo	California	1	260	222	258	230
Richmond	California	1	243	192	224	233
Kapolei	Hawaii	1	54	51	50	50
Salt Lake City	Utah	1	45	42	39	41
Other[1]		1	80	20	31	28
Total Consolidated Companies	**United States**	**6**	**1,012**	**812**	**939**	**845**
Pembroke	United Kingdom	1	210	212	165	186
Cape Town[2]	South Africa	1	110	72	71	61
Burnaby, B.C.	Canada	1	55	49	49	45
Total Consolidated Companies	**International**	**3**	**375**	**333**	**285**	**292**
Affiliates[3]	Various Locations	11	728	688	765	746
Total Including Affiliates	**International**	**14**	**1,103**	**1,021**	**1,050**	**1,038**
Total Including Affiliates	**Worldwide**	**20**	**2,115**	**1,833**	**1,989**	**1,883**

[1] Asphalt plants in Perth Amboy, New Jersey, and Portland, Oregon. The Portland plant was sold in February 2005.

[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 2008.

[3] Chevron sold its 31 percent interest in the Nerefco Refinery in the Netherlands in March 2007. This decreased the company s share of operable capacity by about 124,000 barrels per day.

In the first quarter 2008, the company sold its 4 percent ownership interest in an affiliate that owned a refinery in Abidjan, Côte d Ivoire, decreasing the company s share of operable capacity by about 2,000 barrels per day.

Average crude oil distillation capacity utilization during 2007 was 86 percent, compared with 90 percent in 2006. This decrease generally resulted from unplanned downtime to repair damage resulting from fires in the crude units at the Richmond and Pascagoula refineries during 2007. This impact was partially offset by an improvement in capacity utilization at the Pembroke, U.K., refinery, which had unplanned downtime in 2006. The crude unit at the Pascagoula Refinery was back in service in February 2008. Despite the outage at Pascagoula, the company was able to maintain uninterrupted product supplies to customers through the use of other feedstocks in its gasoline-producing facilities at the refinery. At the U.S. fuel refineries, crude oil distillation capacity utilization averaged 85 percent in 2007, compared with 99 percent in 2006, and cracking and coking capacity utilization averaged 78 percent and 86 percent in 2007 and 2006, respectively. Cracking and coking units, including fluid catalytic cracking units, are the primary facilities used in fuel refineries to convert heavier products into gasoline and other light products.

The company s fuel refineries in the United States, Europe, Canada, South Africa and Australia produce low-sulfur fuels. In 2007, Singapore Refining Company, the company s 50 percent-owned affiliate, began an upgrade project at its 290,000-barrel-per-day refinery in Singapore to produce diesel fuels that meet Euro IV specifications.

In 2007, the company completed modifications at its refineries in El Segundo, California, to enable the processing of heavier crude oils into gasoline, diesel and other light products, and in the United Kingdom to increase the capability to process Caspian-blend crude oils. In October 2007, the company approved plans to construct a $500 million Continuous Catalyst Regeneration unit at the Pascagoula, Mississippi, refinery, which is expected to increase gasoline production by 10 percent, or 600,000 gallons per day, by mid-2010. Design and engineering for a project to increase the

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flexibility to process lower API-gravity crude oils at the company s Richmond, California, refinery continued in 2007. Other upgrade projects at the El Segundo Refinery were being evaluated in early 2008.

In late 2007, GS Caltex, the company s 50 percent-owned affiliate, completed commissioning of new facilities associated with a $1.5 billion upgrade project at the 680,000-barrel-per-day Yeosu refining complex in South Korea. This project is expected to increase the yield of high-value refined products by 33,000 barrels per day, add 15,000 barrels of new lubricant base oil production and reduce feedstock costs through an increase in the refinery s ability to process heavy oil.

Chevron owns a 5 percent interest in Reliance Petroleum Limited, a company formed by Reliance Industries Limited to own and operate a new export refinery being constructed in Jamnagar, India. The refinery is expected to begin operation by year-end 2008, with a crude-oil capacity of 580,000 barrels per day. Chevron has future rights to increase its equity ownership to 29 percent.

Chevron processes imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 87 percent of Chevron s U.S. refinery inputs in 2007 and 2006, respectively.

Gas-to-Liquids

Through the Sasol Chevron Global 50-50 Joint Venture, the company is pursuing gas-to-liquids (GTL) opportunities in several countries.

In Nigeria, Chevron and the Nigerian National Petroleum Corporation are developing a 34,000-barrel-per-day GTL facility at Escravos designed to process natural gas supplied from the Phase 3A expansion of the Escravos Gas Plant (EGP). As of early 2008, approximately 90 percent of engineering and procurement activities had been completed. Chevron has a 75 percent interest in the plant, which is expected to be operational by the end of the decade. Refer also to page 16 for a discussion on the EGP Phase 3A expansion.

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Marketing Operations

The company markets petroleum products throughout much of the world. The principal brands for identifying these products are Chevron, Texaco and Caltex. The table below identifies the company s and affiliates refined products sales volumes, excluding intercompany sales, for the three years ending December 31, 2007.

Refined Products Sales Volumes[1]
(Thousands of Barrels per Day)

	2007	**2006**	**2005**
United States			
Gasolines	728	712	709
Jet Fuel	271	280	291
Gas Oils and Kerosene	221	252	231
Residual Fuel Oil	138	128	122
Other Petroleum Products[2]	99	122	120
Total United States	**1,457**	**1,494**	**1,473**
International[3]			
Gasolines	581	595	662
Jet Fuel	274	266	258
Gas Oils and Kerosene	730	776	781
Residual Fuel Oil	271	324	404
Other Petroleum Products[2]	171	166	147
Total International	**2,027**	**2,127**	**2,252**
Total Worldwide[3]	**3,484**	**3,621**	**3,725**

1	Includes buy/sell arrangements. Refer to Note 13 on page FS-42.		50	217
2	Principally naphtha, lubricants, asphalt and coke.			
3	Includes share of equity affiliates sales:	492	492	498

In the United States, the company markets under the Chevron and Texaco brands. The company supplies directly or through retailers and marketers approximately 9,700 Chevron- and Texaco-branded motor vehicle retail outlets, concentrated in the mid-Atlantic, southern and western states. Approximately 550 of the outlets are company-owned or -leased stations.

Outside the United States, Chevron supplies directly or through retailers and marketers approximately 15,400 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. In Europe, the company markets primarily in the United Kingdom and Ireland under the Texaco brand. In West Africa, the company operates or leases to retailers in Benin, Cameroon, Côte d Ivoire, Nigeria, Republic of the Congo and Togo. In these countries, the company uses the Texaco brand. The company also operates across the Caribbean, Central America and South America, with a significant presence in Brazil, using the Texaco brand. In the Asia-Pacific region, southern, central and east 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, using the GS Caltex brand. The company s 50 percent-owned affiliate in Australia operates using the Caltex, Caltex Woolworths and Ampol brands.

The company continued the marketing and sale of retail fuels networks and individual service station sites, focusing on selected areas outside the United States. In 2007, the company sold its fuels marketing businesses in Belgium, the Netherlands and Luxembourg and its retail fuels business in Uruguay. The company also sold its interest in about 500 individual service station sites, primarily in the United Kingdom and Latin America. Since the beginning of 2003, the company has sold its interests in about 3,300 service station sites. The vast majority of these sites continue to market company-branded gasoline through new supply agreements.

The company also manages other marketing businesses globally. Chevron markets aviation fuel at more than 1,000 airports, representing a worldwide market share of about 11 percent, and is a leading marketer of jet fuels in the United States. The company also markets an extensive line of lubricant and coolant products under brand names that include Havoline, Delo, Ursa, Meropa and Taro.

Transportation Operations

Pipelines: Chevron owns and operates an extensive system of crude oil, refined products, chemicals, natural gas liquids and natural gas pipelines in the United States. The company also has direct or 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, 2007

	Net Mileage[1]
United States:	
Crude Oil[2]	2,853
Natural Gas	2,275
Petroleum Products[3]	7,053
Total United States	**12,181**
International:	
Crude Oil[2]	700
Natural Gas	768
Petroleum Products[3]	426
Total International	**1,894**
Worldwide	**14,075**

1 Partially owned pipelines are included at the company s equity percentage.
2 Includes gathering lines related to the transportation function. Excludes gathering lines related to U.S. and international production activities.
3 Includes refined products, chemicals and natural gas liquids.

During 2007, the company led the development of a natural gas gathering pipeline serving the Piceance Basin in northwest Colorado; participated in the successful installation of the 55-mile Amberjack-Tahiti lateral pipeline on the seafloor of the U.S. Gulf of Mexico; and completed a pipeline running from the U.S. Gulf of Mexico subsea to the Fourchon Terminal in southern Louisiana. The company is also leading the expansion of the West Texas liquefied natural gas pipeline system that is expected to be operational in late 2008. In addition, the company continued with its project to expand capacity by about 2 billion cubic feet at its Keystone natural gas storage facility, which is expected to be completed in 2009.

Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC) affiliate. CPC operates a crude oil export pipeline from the Tengiz Field in Kazakhstan to the Russian Black Sea port of Novorossiysk. During 2007, CPC transported an average of approximately 700,000 barrels of crude oil per day, including 545,000 barrels per day from Kazakhstan and 155,000 barrels per day from Russia. For information related to the possible expansion of the CPC pipeline, refer to page 24.

The company has a 9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate, whose pipeline transports Azerbaijan International Operating Company (AIOC) (owned 10 percent by Chevron) production from Baku, Azerbaijan, through Georgia to deepwater port facilities in Ceyhan, Turkey. The BTC pipeline has a crude-oil capacity of 1 million barrels per day and transports the majority of the AIOC production. Another crude oil production export route is the Western Route Export Pipeline, wholly owned by AIOC, with crude-oil capacity to transport 145,000 barrels per day from Baku, Azerbaijan, to the terminal at Supsa, Georgia.

For information on projects under way related to the West African Gas Pipeline, refer to page 16.

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Tankers: At any given time during 2007, the company had approximately 80 vessels chartered on a voyage basis, or for a period of less than one year. Additionally, all tankers in Chevron s controlled seagoing fleet were utilized during 2007. The following table summarizes cargo transported on the company s controlled fleet.

Controlled Tankers at December 31, 2007

	U.S. Flag		Foreign Flag	
	Number	**Cargo Capacity (Millions of Barrels)**	**Number**	**Cargo Capacity (Millions of Barrels)**
Owned	3	0.8	1	1.1
Bareboat Chartered	1	0.3	19	28.1
Time Chartered*			24	14.3
Total	**4**	**1.1**	**44**	**43.5**

* One year or more.

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. In 2007, the company s U.S. flag fleet was 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. Three U.S.-flagged product tankers, each capable of carrying 300,000 barrels of cargo, are scheduled for delivery from 2008 through 2010.

The foreign-flagged vessels were engaged primarily in transporting crude oil from the Middle East, Asia, the Black Sea, Mexico and West Africa to ports in the United States, Europe, Australia and Asia. Refined products were also transported by tanker worldwide. During 2007, the company took delivery of one new double-hulled tanker, with a total capacity of 500,000 barrels, and one U.S.-flagged product tanker capable of carrying 300,000 barrels of cargo. The company also returned a 1 million-barrel-capacity crude tanker at the end of its lease.

In addition to the vessels described above, the company owns a one-sixth interest in each of seven liquefied natural gas (LNG) tankers transporting cargoes for the North West Shelf (NWS) Venture in Australia. The NWS project also has two LNG tankers under long-term time charter. In 2005, Chevron placed orders for two company-owned LNG tankers.

The Federal Oil Pollution Act of 1990 requires the phase-out by year-end 2010 of all single-hull tankers trading to U.S. ports or transferring cargo in waters within the U.S. Exclusive Economic Zone. This has raised the demand for double-hull tankers. At the end of 2007, 100 percent of the company s owned and bareboat-chartered fleet was double-hulled. The company is a member of many oil-spill-response cooperatives in areas in which it operates around the world.

Chemicals

Chevron Phillips Chemical Company LLC (CPChem) is equally owned with ConocoPhillips Corporation. At the end of 2007, CPChem owned or had joint venture interests in 30 manufacturing facilities and six research and technical centers in Belgium, China, Puerto Rico, Qatar, Saudi Arabia, Singapore, South Korea and the United States.

In 2007, CPChem completed construction on the integrated, world-scale styrene facility in Al Jubail, Saudi Arabia. Jointly owned with the Saudi Industrial Investment Group (SIIG), commercial production is expected to commence in mid-2008. The styrene facility is located adjacent to CPChem and SIIG s existing aromatics complex in Al Jubail. Also during 2007, CPChem secured final approval for a third petrochemical project in Al Jubail. Construction began in early 2008, with expected completion in 2011. Preliminary studies are focused on the construction of a world-scale olefins unit as well as related downstream units to produce polyethylene, polypropylene, 1-hexene and polystyrene. In the first half of 2008, commercial operations are expected to begin for the Americas Styrenics joint venture between CPChem and Dow Chemical Company that combines CPChem s styrene and polystyrene operations with Dow s polystyrene operations.

CPChem continued construction during 2007 on the 49 percent-owned Q-Chem II project in Mesaieed, Qatar. The project includes a 350,000-metric-ton-per-year polyethylene plant and a 345,000-metric-ton-per-year normal alpha olefins plant each utilizing CPChem proprietary technology and is located adjacent to the existing Q-Chem I complex. Q-Chem II also includes a separate joint venture to develop a 1.3 million-metric-ton-per-year ethylene cracker at Qatar s Ras Laffan Industrial City, in which Q-Chem II owns 54 percent of the capacity rights. CPChem and its partners expect to start up the plants in the first half of 2009. Construction also began during 2007 of the Ryton® polyphenylene sulfide manufacturing facility in Texas, with completion scheduled for 2009.

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 provides additives for lubricating oil in most engine applications, such as passenger car, heavy-duty diesel, marine, locomotive and motorcycle engines, and additives for fuels to improve engine performance and extend engine life. Oronite has completed construction of the new carboxylate detergent unit in France. This facility will produce new sulfur-free detergent components for marine engine applications and low-sulfur components for automotive engine oil applications. Full commercial production from this facility is expected to commence early in the second quarter 2008.

Other Businesses

Mining

Chevron s U.S.-based mining company produces and markets coal, molybdenum, rare earth minerals and calcined petroleum coke. Sales occur in both U.S. and international markets.

In 2007, the company s coal mining and marketing subsidiary, The Pittsburg & Midway Coal Mining Co. (P&M), changed its name to Chevron Mining Inc. (CMI) and merged with Molycorp Inc., another Chevron mining subsidiary, to form a single Chevron mining entity. The company owns and operates two surface coal mines, McKinley, in New Mexico, and Kemmerer, in Wyoming, and one underground coal mine, North River, in Alabama. Sales of coal from CMI s wholly owned mines were 12 million tons, down about 1 million tons from 2006.

At year-end 2007, CMI controlled approximately 214 million tons of proven and probable coal reserves in the United States, including reserves of environmentally desirable low-sulfur coal. The company is contractually committed to deliver between 11 million and 12 million tons of coal per year through the end of 2009 and believes it will satisfy these contracts from existing coal reserves.

In addition to the coal operations, Chevron owns and operates the Questa molybdenum mine in New Mexico and the Mountain Pass rare earth mine in California. At year-end 2007, CMI controlled approximately 57 million pounds of proven molybdenum reserves at Questa and 241 million pounds of proven and probable rare earth reserves at Mountain Pass.

Chevron also owns a 33 percent interest in Sumikin Molycorp, a manufacturer of neodymium compounds, located in Japan, and a 50 percent interest in Youngs Creek Mining Company LLC, a joint venture to develop a coal mine in northern Wyoming. The company also owns the Chicago Carbon Company, a producer and marketer of calcined petroleum coke, which operates a 250,000-ton-per-year petroleum coke calciner facility in Lemont, Illinois.

Power Generation

Chevron s power generation business develops and operates commercial power projects and owns 15 power assets located in the United States and Asia. The company manages the production of more than 2,334 megawatts of electricity at 11 facilities it owns through joint ventures. The company operates gas-fired cogeneration facilities that use waste heat recovery to produce additional electricity or to support industrial thermal hosts. A number of the facilities produce steam for use in upstream operations to facilitate production of heavy oil.

The company has major geothermal operations in Indonesia and the Philippines and is investigating several advanced solar technologies for use in oil field operations as part of its renewable energy strategy. For additional information on the company s geothermal operations and renewable energy projects, refer to pages 19 and 20, and the Research and Technology section below, respectively.

Chevron Energy Solutions

Chevron Energy Solutions (CES) is a wholly owned subsidiary that provides public institutions and businesses with projects designed to increase energy efficiency and reliability, reduce energy costs, and utilize renewable and alternative power technologies. CES has energy-saving projects installed in more than a thousand buildings nationwide. Major projects completed by CES in 2007 include energy efficiency installations for the state of Colorado government facilities and a 1.1 megawatt solar system at California s Fresno State University.

Research and Technology

The company s Energy Technology Company (ETC) supports Chevron s upstream and downstream businesses. ETC provides technology and competency support in earth sciences; reservoir and production engineering; drilling and completions; facilities engineering; health, environment and safety; refining; technical computing; strategic planning; and organizational capability.

Technology Ventures Company manages investments and projects in emerging energy technologies and their integration into Chevron s core businesses. Its activities are managed through four business units: Venture Capital, Biofuels, Hydrogen and Emerging Energy.

Information Technology Company integrates computing, telecommunications, data management, security and network technology to provide a standardized digital infrastructure for Chevron s global operations.

During 2007, the company entered into research alliances with Texas A&M University, with focus on the production and conversion of crops for biofuels from cellulose, and the Colorado Center for Biorefining and Biofuel, with focus on conversion technologies. The company also has research alliances with the University of California, Davis and the Georgia Institute of Technology that are focused on converting cellulosic biomass into transportation fuels.

Chevron s research and development expenses were $562 million, $468 million and $316 million for the years 2007, 2006 and 2005, respectively.

Some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, and ultimate successes are not certain. Although not all initiatives may prove to be economically viable, the company s overall investment in this area is not significant to the company s consolidated financial position.

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. Chevron expects more environment-related regulations in the countries where it has operations. Most of the costs of complying with the many laws and regulations pertaining to its operations are embedded in the normal costs of conducting business.

In 2007, the company s U.S. capitalized environmental expenditures were approximately $350 million, representing approximately 5 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 are predominantly in the upstream and downstream segments and relate mostly to air- and water-quality projects and activities at the company s refineries, oil and gas producing facilities, and marketing facilities. For 2008, the company estimates U.S. capital expenditures for environmental control facilities will be approximately $580 million. The future annual capital costs of fulfilling this commitment are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Further information on environmental matters and their impact on Chevron and on the company s 2007 environmental expenditures, remediation provisions and year-end environmental reserves are contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages FS-16 and FS-17.

Web Site Access to SEC Reports

The company s Internet Web site can be found at 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 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 at the SEC s Web site, www.sec.gov.

Item 1A. Risk Factors

Chevron is a major fully integrated petroleum 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 crude-oil prices. Except in the ordinary course of running an integrated petroleum business, Chevron does not seek to hedge its exposure to price changes. A significant, persistent decline in crude-oil prices may have a material adverse effect on its results of operations and its capital and exploratory expenditure plans.

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, 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, including hurricanes, floods and other forms of severe weather, war, civil unrest and other political events, fires, earthquakes, and explosions, any of which could result in suspension of operations or harm to people or the natural environment.

Chevron s business subjects the company to liability risks.

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. Any of these activities could result in liability, 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.

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 and/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, 2007, 26 percent of the company s proved reserves were located in Kazakhstan. The company also has significant interests in Organization of Petroleum Exporting Countries (OPEC) member countries including Angola, Indonesia, Nigeria and Venezuela. Twenty-eight percent of the company s net proved reserves, including affiliates, were located in OPEC countries at December 31, 2007.

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Regulation of greenhouse gas emissions could increase Chevron s operational costs and reduce demand for Chevron s products.

Management believes it is reasonably likely that the scientific and political attention to issues concerning the existence and extent of climate change, and the role of human activity in it, will continue, with the potential for further regulation that affects the company s operations. Although uncertain, these developments could increase costs or reduce the demand for the products the company sells. The company s production and processing operations (e.g., the production of crude oil at offshore platforms and the processing of natural gas at liquefied natural gas facilities) typically result in emissions of greenhouse gases. Likewise, emissions arise from midstream and downstream operations, including crude oil transportation and refining. Finally, although beyond the control of the company, the use of passenger vehicle fuels and related products by consumers also results in greenhouse gas emissions that may be regulated.

International agreements, domestic legislation and regulatory measures to limit greenhouse gas emissions are currently in various phases of discussion or implementation. These include the Kyoto Protocol, proposed federal legislation and current state-level actions. Some of the countries in which Chevron operates have ratified the Kyoto Protocol, and the company is currently complying with greenhouse gas emissions limits within the European Union. Although resolutions supporting cap and trade systems have been introduced in the U.S. Congress, no bill restricting greenhouse gas emissions has been passed to date.

In California, the Global Warming Solutions Act became effective on January 1, 2007. This law caps California s greenhouse gas emissions at 1990 levels by 2020; directs the Air Resources Board, the responsible state agency, to determine certain greenhouse gas emissions in and outside California to adopt mandatory reporting rules for significant sources of greenhouse gases; delegates to the agency the authority to adopt compliance mechanisms (including market-based approaches); and permits a one-year extension of the targets under extraordinary circumstances. Related regulatory activity is under way within the California Public Utilities Commission. The Air Resources Board and the California Energy Commission are also in the process of developing a Low Carbon Fuel Standard for transportation fuels used in California, as directed by Governor Arnold Schwarzenegger. The company extracts crude oil and natural gas, operates refineries, and markets and sells gasoline, diesel and jet fuel in California. The extent to which the state and local agencies regulations will affect the company s California operations was not known as of early 2008.

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 the Securities Exchange Act Industry Guide No. 2 (Disclosure of Oil and Gas Operations) is also contained in Item 1 and in Tables I through VII on pages FS-61 to FS-74. Note 12, Properties, Plant and Equipment, to the company s financial statements is on page FS-42.

Item 3. Legal Proceedings

In January 2008, Chevron agreed to pay the state of New York a $162,500 civil penalty in connection with a February 2006 oil spill at the company s facility in Perth Amboy, New Jersey.

Item 4. Submission of Matters to a Vote of Security Holders

None.

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
Oct. 1 Oct. 31, 2007	**4,225,293**	**92.09**	4,038,000	
Nov. 1 Nov. 30, 2007	**10,455,696**	**86.46**	10,200,000	
Dec. 1 Dec. 31, 2007	**8,375,829**	**90.82**	8,221,763	
Total Oct. 1 Dec. 31, 2007	**23,056,818**	**89.08**	22,459,763	(2)

(1) Includes 42,494 common shares repurchased during the three-month period ended December 31, 2007, from company employees for required personal income tax withholdings on the exercise of the stock options issued to management and employees under the company s broad-based employee stock options, long-term incentive plans and former Texaco Inc. stock option plans. Also includes 554,561 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, 2007.

(2) In September 2007, the company authorized stock repurchases of up to $15 billion that may be made from time to time at prevailing prices as permitted by securities laws and other requirements and subject to market conditions and other factors. The program will occur over a period of up to three years and may be discontinued at any time. As of December 31, 2007, 23,530,209 shares had been acquired under this program for $2.1 billion.

Item 6. Selected Financial Data

The selected financial data for years 2003 through 2007 are presented on page FS-60.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The company s discussion of interest rate, foreign currency and commodity price market risk is contained in Management s Discussion and Analysis of Financial Condition and Results of Operations Financial and Derivative Instruments, beginning on page FS-14 and in Note 7 to the Consolidated Financial Statements, Financial and Derivative Instruments, beginning on page FS-36.

Item 8. Financial Statements and Supplementary Data

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

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

None.

Item 9A. Controls and Procedures

(a) **Evaluation of Disclosure Controls and Procedures**

Chevron Corporation s Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of the company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)), as of December 31, 2007, have concluded that as of December 31, 2007, the company s disclosure controls and procedures were effective and designed to provide reasonable assurance that material information relating to the company and its consolidated subsidiaries required to be included in the company s periodic filings under the Exchange Act would be made known to them by others within those entities.

(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 Rules 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, 2007.

The effectiveness of the company s internal control over financial reporting as of December 31, 2007, 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, 2007, there were no changes in the company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company s internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 28, 2008

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
D.J. O Reilly	61	Chairman of the Board and Chief Executive Officer (since 2000)	Chief Executive Officer
P.J. Robertson	61	Vice Chairman of the Board (since 2002) President of Chevron Overseas Petroleum Inc. (2000 to 2002)	Policy, Government and Public Affairs; Human Resources
J.E. Bethancourt	56	Executive Vice President (since 2003) Vice President of Human Resources (2001 to 2003)	Technology; Chemicals; Mining; Health, Environment and Safety
G.L. Kirkland	57	Executive Vice President (since 2005) President of Chevron Overseas Petroleum Inc. (2002 to 2004) President of Chevron U.S.A. Production Company (2000 to 2002)	Worldwide Exploration and Production Activities and Global Gas Activities, including Natural Gas Trading
J.S. Watson	51	Executive Vice President (since 2008) Vice President and President of Chevron International Exploration and Production Company (2005 through 2007) Vice President and Chief Financial Officer (2000 through 2004)	Business Development; Mergers and Acquisitions; Strategic Planning; Project Resources Company
M.K. Wirth	47	Executive Vice President (since 2006) President of Global Supply and Trading (2004 to 2006) President of Marketing, Asia, Middle East and Africa Marketing Business Unit (2001 to 2004)	Global Refining, Marketing, Lubricants, and Supply and Trading, excluding Natural Gas Trading
S.J. Crowe	60	Vice President and Chief Financial Officer (since 2005) Vice President and Comptroller (from 2000 through 2004)	Finance
C.A. James	53	Vice President and General Counsel (since 2002)	Law

The information on Directors appearing under the heading Election of Directors Nominees for Directors in the Notice of the 2008 Annual Meeting of Stockholders and 2008 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 2008 Annual Meeting of Stockholders (the 2008 Proxy Statement), is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading Stock Ownership Information Section 16(a) Beneficial Ownership Reporting Compliance in the 2008 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading Board Operations Business Conduct and Ethics Code in the 2008 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading Board Operations Board Committee Membership and Functions in the 2008 Proxy Statement is incorporated by reference in 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 appearing under the headings Executive Compensation and Directors Compensation in the 2008 Proxy Statement is incorporated herein by reference in this Annual Report on Form 10-K.

The information contained under the heading Board Operations Board Committee Membership and Functions in the 2008 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

The information appearing under the heading Management Compensation Committee Report in the 2008 Proxy Statement is incorporated herein by reference in 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 2008 Proxy Statement shall not be deemed filed for purposes of Section 18 of the Exchange Act nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information appearing under the heading Stock Ownership Information Security Ownership of Certain Beneficial Owners and Management in the 2008 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

The information contained under the heading Equity Compensation Plan Information in the 2008 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information appearing under the heading Board Operations Transactions With Related Persons in the 2008 Proxy Statement is incorporated by reference in this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services

The information appearing under the heading Ratification of Independent Registered Public Accounting Firm in the 2008 Proxy Statement is incorporated by reference in 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:

We have included, on page 39, Schedule II Valuation and Qualifying Accounts.

(3) Exhibits:

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

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SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS
Millions of Dollars

	Year Ended December 31		
	2007	**2006**	**2005**
Employee Termination Benefits:			
Balance at January 1	$ 28	$ 91	$ 137
Additions (deductions) charged (credited) to expense	106	(21)	(21)
Additions related to Unocal acquisition			106
Payments	(17)	(42)	(131)
Balance at December 31	**$ 117**	**$ 28**	**$ 91**
Allowance for Doubtful Accounts:			
Balance at January 1	$ 217	$ 198	$ 219
Additions charged to expense	29	61	3
Additions related to Unocal acquisition			6
Bad debt write-offs	(46)	(42)	(30)
Balance at December 31	**$ 200**	**$ 217**	**$ 198**
Deferred Income Tax Valuation Allowance:*			
Balance at January 1	$ 4,391	$ 3,249	$ 1,661
Additions charged to deferred income tax expense	1,894	1,700	1,593
Additions related to Unocal acquisition			400
Deductions credited to goodwill		(77)	(60)
Deductions credited to deferred income tax expense	(336)	(481)	(345)
Balance at December 31	**$ 5,949**	**$ 4,391**	**$ 3,249**

* See also Note 15 to the Consolidated Financial Statements beginning on page FS-43.

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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 28th day of February, 2008.

Chevron Corporation

By /s/ David J. O Reilly
David J. O Reilly, 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 28th day of February, 2008.

Principal Executive Officers (and Directors)	Directors
/s/David J. O Reilly David J. O Reilly, Chairman of the Board and Chief Executive Officer	Samuel H. Armacost* Samuel H. Armacost
/s/Peter J. Robertson Peter J. Robertson, Vice Chairman of the Board	Linnet F. Deily* Linnet F. Deily
	Robert E. Denham* Robert E. Denham
	Robert J. Eaton* Robert J. Eaton
	Sam Ginn* Sam Ginn
Principal Financial Officer /s/Stephen J. Crowe Stephen J. Crowe, Vice President and Chief Financial Officer	Franklyn G. Jenifer* Franklyn G. Jenifer
Principal Accounting Officer /s/Mark A. Humphrey Mark A. Humphrey, Vice President and Comptroller	Sam Nunn* Sam Nunn
	Donald B. Rice* Donald B. Rice
*By: /s/Lydia I. Beebe Lydia I. Beebe,	Kevin W. Sharer* Kevin W. Sharer

Attorney-in-Fact

Charles R. Shoemate*
Charles R. Shoemate

Ronald D. Sugar*
Ronald D. Sugar

Carl Ware*
Carl Ware

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CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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Notes to the Consolidated Financial Statements

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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	**2007**	2006	2005
Net Income	**$ 18,688**	$ 17,138	$ 14,099
Per Share Amounts:			
Net Income Basic	**$ 8.83**	$ 7.84	$ 6.58
Diluted	**$ 8.77**	$ 7.80	$ 6.54
Dividends	**$ 2.26**	$ 2.01	$ 1.75
Sales and Other Operating Revenues	**$ 214,091**	$ 204,892	$ 193,641
Return on:			
Average Capital Employed	**23.1%**	22.6%	21.9%
Average Stockholders Equity	**25.6%**	26.0%	26.1%

Income by Major Operating Area

Millions of dollars	**2007**	2006	2005
Upstream Exploration and Production			
United States	**$ 4,532**	$ 4,270	$ 4,168
International	**10,284**	8,872	7,556
Total Upstream	**14,816**	13,142	11,724
Downstream Refining, Marketing and Transportation			
United States	**966**	1,938	980
International	**2,536**	2,035	1,786
Total Downstream	**3,502**	3,973	2,766
Chemicals	**396**	539	298
All Other	**(26)**	(516)	(689)
Net Income*	**$ 18,688**	$ 17,138	$ 14,099
*Includes Foreign Currency Effects:	**$ (352)**	$ (219)	$ (61)

Refer to the Results of Operations section beginning on page FS-6 for a detailed discussion of financial results by major operating area for the three years ending December 31, 2007.

Business Environment and Outlook

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

Current and future earnings of the company depend largely on the profitability of its upstream (exploration and production) and downstream (refining, marketing and transportation) 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 chemicals business and other activities and investments. Earnings for the company in any period may also be influenced by events or transactions that are infrequent and/or unusual in nature.

Chevron and the oil and gas industry at large continue to experience an increase in certain costs that exceeds the general trend of inflation in many areas of the world. This increase in costs is affecting the company s operating expenses and capital expenditures, particularly for the upstream business. 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 adequate 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. In the current environment of higher commodity prices, certain governments have sought to renegotiate contracts or impose additional costs on the company. Other 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 growth. Asset sales during 2007 included the company s 31 percent ownership interest in a refinery and related assets in the Netherlands; fuels marketing businesses in Belgium, Luxembourg, the Netherlands and Uruguay; and the investment in common stock of Dynegy Inc. Other asset dispositions and restructurings may occur in future periods and could result in significant gains or losses.

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 attempts to manage risks in operating its facilities and business.

Price levels for capital and exploratory costs and operating expenses associated with the efficient 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 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. The oil and gas industry worldwide has experienced significant price increases for these items since 2005, and future price increases may continue to exceed the general level of inflation. Capital and exploratory expenditures and operating expenses also can be affected by damages to production facilities caused by severe weather or civil unrest.

Industry price levels for crude oil increased during 2007. The spot price for West Texas Intermediate (WTI) crude oil, a benchmark crude oil, averaged $72 per barrel in 2007, up approximately $6 per barrel from the 2006 average price. The rise in crude oil prices was attributed primarily to increasing demand in growing economies, the heightened level of geopolitical uncertainty in some areas of the world and supply concerns in other key producing regions. As of mid-February 2008, the WTI price was about $93 per barrel.

As in 2006, a wide differential in prices existed in 2007 between high-quality (i.e., high-gravity, low sulfur) crude oils

and those of lower quality (i.e., low-gravity, heavier types of crude). The price for the heavier crudes has been dampened because of ample supply and lower relative demand due to the limited number of refineries that are able to process this lower-quality feedstock into light products (i.e., motor gasoline, jet fuel, aviation gasoline and diesel fuel). The price for higher-quality crude oil has remained high, as the demand for light products, which can be more easily manufactured by refineries from high-quality crude oil, has been strong worldwide. Chevron produces or shares in the production of heavy crude oil in California, Chad, Indonesia, the Partitioned Neutral Zone between Saudi Arabia and Kuwait, Venezuela and certain fields in Angola, China and the United Kingdom North Sea. (Refer to page FS-l0 for the company s average U.S. and international crude oil prices.)

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 during 2007, benchmark prices at Henry Hub averaged about $7 per thousand cubic feet (MCF), compared with about $6.50 in 2006. As of mid-February 2008, the Henry Hub price was about $8 per MCF. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. U.S. natural gas prices are also typically higher during the winter period when demand for heating is greatest.

Certain other regions of the world in which the company operates have different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices for the company s production of natural gas. (Refer to page FS-l0 for the company s average natural gas prices for the U.S. and international regions.) Additionally, excess-supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-

price conditions in the United States and other markets because of the lack of infrastructure to transport and receive liquefied natural gas.

To help address this regional imbalance between supply and demand for natural gas, Chevron is planning increased investments in long-term projects in areas of excess supply to install infrastructure to produce and liquefy natural gas for transport by tanker, along with investments and commitments to regasify the product in markets where demand is strong and supplies are not as plentiful. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices in the areas of excess supply (before the natural gas is transferred to a company-owned or third-party processing facility) are expected to remain well below sales prices for natural gas that is produced much nearer to areas of high demand and can be transported in existing natural gas pipeline networks (as in the United States).

Besides the impact of the fluctuation in price 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, changes in tax rates on income, and the cost of goods and services.

Chevron s worldwide net oil-equivalent production in 2007, including volumes produced from oil sands, averaged 2.62 million barrels per day, a decline of about 48,000 barrels per day from 2006, due mainly to the effect of a conversion of operating service agreements in Venezuela to joint-stock companies. (Refer to the table Selected Operating Data on page FS-10 for a listing of production volumes for each of the three years ending December 31, 2007.) The company estimates that oil-equivalent production in 2008 will average approximately 2.65 million barrels per day. This estimate is subject to many uncertainties, including quotas that may be imposed by OPEC, the price effect on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, changes in fiscal terms or restrictions on the scope of company operations, delays in project start-ups, weather conditions that may shut in production, civil unrest, changing geopolitics or other disruptions to operations. Future production levels also are 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. Most of Chevron s upstream investment is currently being made outside the United States. Investments in upstream projects generally are made well in advance of the start of the associated crude oil and natural gas production.

Approximately 28 percent of the company s net oil-equivalent production in 2007 occurred in the OPEC-member countries of Angola, Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. OPEC quotas did not significantly affect Chevron s production level in 2007.
The impact of OPEC quotas on the company s production in 2008 is uncertain.

In October 2006, Chevron s Boscan and LL-652 operating service agreements in Venezuela were converted to Empresas Mixtas (i.e., joint-stock companies), with Petróleos de Venezuela, S.A. (PDVSA) as majority shareholder. From that time, Chevron reported its equity share of the Boscan and LL-652 production, which was approximately 85,000 barrels per day less than what the company previously reported under the operating service agreements. The change to the Empresa Mixta structure did not have a material effect on the company s results of operations, consolidated financial position or liquidity.

In February 2007, the president of Venezuela issued a decree announcing the government s intention for PDVSA to take over operational control of all Orinoco Heavy Oil Associations effective May 1, 2007, and to increase its ownership in all such Associations to a minimum of 60 percent. The decree included Chevron s 30 percent-owned Hamaca project. In April 2007, Chevron signed a memorandum of understanding (MOU) with PDVSA that summarized the ongoing discussions to transfer control of Hamaca operations in accordance with the February decree.

As provided in the MOU, a PDVSA-controlled transitory operational committee, on which Chevron had representation, assumed responsibility for daily operations on May 1, 2007. The MOU stipulated that terms of existing contracts were to remain in place during the transition period. In December 2007, Chevron executed a conversion agreement and signed a charter and by-laws with a PDVSA subsidiary that provided for Chevron to retain its 30 percent interest in the Hamaca project. The new entity, Petropiar, commenced activities in January 2008. The conversion agreement did not have a material effect on Chevron s results of operations, consolidated financial position or liquidity.

Refer to pages FS-6 through FS-7 for additional discussion of the company s upstream operations.

Downstream Earnings for the downstream segment are closely tied to margins on the refining and marketing of products that include gasoline, diesel, jet fuel, lubricants, fuel oil and feedstocks for chemical manufacturing. Industry margins are sometimes volatile and can be affected by the global and regional supply-and-demand balance for refined products and by changes in the price of crude oil used for refinery feedstock. Industry margins can also be influenced by refined-product inventory levels, geopolitical events, refinery maintenance programs and disruptions at refineries resulting from unplanned outages that may be 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 and marketing network, the effectiveness of the crude-oil and product-supply functions and the economic returns on invested capital. Profitability can also be affected by 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 refinery and distribution network.

The company s most significant marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia, sub-Saharan Africa and the United Kingdom. Chevron operates or has ownership interests in refineries in each of these areas except Latin America. For the industry, refined-product margins were generally higher in 2007 than in 2006. For the company, U.S. refined-product margins during 2007 were negatively affected by planned and unplanned downtime at its three largest U.S. refineries.

Industry margins in the future may be volatile and are influenced by changes in the price of crude oil used for refinery feedstock and by changes in the supply and demand for crude oil and refined products. The industry supply and demand balance can be affected by disruptions at refineries resulting from maintenance programs and unplanned outages, including weather-related disruptions; refined-product inventory levels; and geopolitical events.

Refer to page FS-7 through FS-8 for additional discussion of the company s downstream operations.

Chemicals Earnings in the petrochemicals business are closely tied to global chemical demand, industry inventory levels and plant capacity utilization. Feedstock and fuel costs, which tend to follow crude oil and natural gas price movements, also influence earnings in this segment.

Refer to page FS-8 for additional discussion of chemicals earnings.

Operating Developments

Key operating developments and other events during 2007 and early 2008 included the following:

Upstream

Angola Discovered crude oil at the 31 percent-owned and operated Malange-1 well in offshore Block 14. Additional drilling and geologic and engineering studies are planned to appraise the discovery. The company and partners also made the final investment decision to construct a liquefied natural gas (LNG) plant that will be owned 36 percent by Chevron. The plant will be designed

with a capacity to process 1 billion cubic feet of natural gas per day and produce 5.2 million metric tons a year of LNG and related gas liquids products.

Australia Received federal and state environmental approvals for development of the 50 percent-owned and operated Gorgon LNG project located off the northwest coast. The approvals represented a significant milestone towards the development of the company s natural gas resources offshore Australia.

Bangladesh Began production at the 98 percent-owned Bibiyana natural gas field. The field s total production is expected to increase to a maximum of 500 million cubic feet per day by 2010.

China Signed a 30-year production-sharing contract with China National Petroleum Corporation to assume operatorship and hold a 49 percent interest in the development of the Chuandongbei natural gas area in central China. Design input capacity of the proposed gas plants is expected to be 740 million cubic feet of natural gas per day.

Indonesia Began commercial operation of the 110-megawatt Darajat III geothermal power plant in Garut, West Java. The plant increased Darajat s total capacity to 259 megawatts.

Kazakhstan Initiated production from the first phase of the Sour Gas Injection and Second Generation Plant expansion projects at the 50 percent-owned Tengiz Field. This phase increased production capacity by 90,000 barrels of crude oil per day to approximately 400,000. Full facility expansion is expected to occur during the second-half

2008, increasing production capacity to 540,000 barrels per day.

Republic of the Congo Confirmed two crude oil discoveries in the offshore Moho-Bilondo permit. Evaluation and development studies were undertaken to appraise the discoveries, in which Chevron holds a 32 percent nonoperated working interest.

Thailand Signed an agreement to increase sales of natural gas from company-operated Blocks 10, 11, 12 and 13 in the Gulf of Thailand to PTT Public Company Limited. Chevron has ownership interests ranging from 60 percent to 80 percent in the blocks, which received 10-year production-period extensions to 2022. The company was also granted the concession rights for a six-year period to four prospective offshore petroleum blocks, three of which it will operate.

Trinidad and Tobago Signed an agreement to sell natural gas to the National Gas Company of Trinidad and Tobago for 11 years with an option for a four-year extension. The gas is expected to be sourced from Chevron s 50 percent-owned East Coast Marine Area.

United States Announced that first production from the Tahiti project in the deepwater Gulf of Mexico is expected by the third quarter 2009. The start-up is approximately one year later than originally planned due to metallurgical problems with the mooring shackles for the floating production facility.

Downstream

Benelux Countries Sold the company s 31 percent interest in the Nerefco Refinery and related assets in the Netherlands, and the company s fuels marketing businesses in Belgium, Luxembourg and the Netherlands, resulting in gains totaling $960 million.

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South Korea Completed construction and commissioned new facilities associated with a $1.5 billion upgrade at the 50 percent-owned GS Caltex Yeosu Refinery, enabling the refinery to process heavier and higher-sulfur crude oils and increase the production of gasoline, diesel and other light products.

United States Approved plans at the company s refinery in Pascagoula, Mississippi, for the construction of a Continuous Catalyst Regeneration unit, which is expected to increase gasoline production by 10 percent, or 600,000 gallons per day, by mid-2010. At the refinery in El Segundo, California, modifications were completed to enable the processing of heavier crude oils into light transportation fuels and other refined products.

Other

Common Stock Dividends Increased the company s quarterly common stock dividend by 11.5 percent in April to $0.58 per share, marking the 20th consecutive year the company has increased its annual dividend payment.

Common Stock Repurchase Program Approved a program in September to acquire up to $15 billion of the company s common stock over a period of up to three years, which followed three stock repurchase programs of $5 billion each that were completed in 2005, 2006 and September 2007.

Dynegy Sold the company s common stock investment in Dynegy Inc., resulting in a gain of $680 million.

Results of Operations

Major Operating Areas The following section presents the results of operations for the company s business segments upstream, downstream and chemicals as well as for all other, which includes mining, power generation businesses, the various companies and departments that are managed at the corporate level, and the company s investment in Dynegy prior to its sale in May 2007. Income is also presented for the U.S. and international geographic areas of the upstream and downstream business segments. (Refer to Note 8, beginning on page FS-37, for a discussion of the company s reportable segments, as defined in FASB No. 131, Disclosures About Segments of an Enterprise and Related Information.) 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 Exploration and Production

Millions of dollars	**2007**	2006	2005
Income	**$ 4,532**	$ 4,270	$ 4,168

U.S. upstream income of $4.5 billion in 2007 increased approximately $260 million from 2006. Results in 2007 benefited approximately $700 million from higher prices for crude oil and natural gas liquids. This benefit to income was partially offset by the

effects of a decline in oil-equivalent production and an increase in depreciation, operating and exploration expenses.

Income of $4.3 billion in 2006 increased approximately $100 million from 2005. Earnings in 2006 benefited about $850 million from higher average prices on oil-equivalent production and the effect of seven additional months of production from the Unocal properties that were acquired in August 2005. Substantially offsetting these benefits were increases in operating, exploration and depreciation expenses. Included in the operating expense increases were costs associated with the carryover effects of hurricanes in the Gulf of Mexico in 2005.

The company s average realization for crude oil and natural gas liquids in 2007 was $63.16 per barrel, compared with $56.66 in 2006 and $46.97 in 2005. The average natural gas realization was $6.12 per thousand cubic feet in 2007, compared with $6.29 and $7.43 in 2006 and 2005, respectively.

Net oil-equivalent production in 2007 averaged 743,000 barrels per day, down 2.6 percent from 2006 and up 2 percent from 2005, which included only five months of production from the Unocal properties acquired in August of that year. The net liquids component of oil-equivalent production for 2007 averaged 460,000 barrels a day, which was essentially flat compared with 2006, and an increase of 1 percent from 2005. Net natural gas production averaged 1.7 billion cubic feet per day in 2007, down 6 percent from 2006 and up 4 percent from 2005.

Refer to the Selected Operating Data table, on page FS-10, for the three-year comparative production volumes in the United States.

International Upstream - Exploration and Production

Millions of dollars	**2007**	2006	2005
Income*	**$ 10,284**	$ 8,872	$ 7,556
*Includes Foreign Currency Effects:	**$ (417)**	$ (371)	$ 14

International upstream income of $10.3 billion in 2007 increased $1.4 billion from 2006. Earnings in 2007 benefited approximately $1.6 billion from higher prices, primarily for crude oil, and $300 million from increased liftings. Non-recurring income tax items also benefited earnings between periods. These benefits to income were partially offset by the impact of higher operating and depreciation expenses.

Income in 2006 of approximately $8.9 billion increased $1.3 billion from 2005. Earnings in 2006 benefited approximately $3 billion from higher prices for crude oil and natural gas and an additional seven months of production from the former Unocal properties. About 70 percent of this benefit was associated with the impact of higher prices. Substantially offsetting these benefits were increases in depreciation expense, operating expense and exploration expense. Also adversely affecting 2006 income were higher taxes related to an increase in tax rates in the U.K. and Venezuela and settlement of tax claims and other tax items in Venezuela, Angola and Chad. Foreign currency effects reduced earnings by $371 million in 2006, but increased income $14 million in 2005.

The company s average realization for crude oil and natural gas liquids in 2007 was $65.01 per barrel, compared with $57.65 in 2006 and $47.59 in 2005. The average natural gas realization was $3.90 per thousand cubic feet in 2007, compared with $3.73 and $3.19 in 2006 and 2005, respectively.

Net oil-equivalent production of 1.88 million barrels per day in 2007 declined about 2 percent from 2006 and increased 5 percent from 2005. The volumes for each year included production from oil sands in Canada and an operating service agreement in Venezuela until its conversion to a joint-stock company in October 2006. The decline between 2006 and 2007 was associated with the impact of this contract conversion in Venezuela and the price effects on production volumes calculated under production-sharing agreements. Partially offsetting the decline was increased production in Bangladesh, Angola and Azerbaijan. The increase from 2005 was due to that year having included only five months of production from the former Unocal properties.

The net liquids component of oil-equivalent production was 1.3 million barrels per day in 2007, a decrease of approximately 4 percent from 2006 and 3 percent from 2005. Net natural gas production of 3.3 billion cubic feet per day in 2007 was up 5.5 percent and 28 percent from 2006 and 2005, respectively.

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

US. Downstream - Refining, Marketing and Transportation

Millions of dollars	**2007**	2006	2005
Income	**$ 966**	$ 1,938	$ 980

U.S. downstream earnings of $966 million in 2007 declined nearly $1 billion from 2006 and were essentially the same as 2005. The decline in 2007 from 2006 was associated mainly with weaker refined-product margins due to the effects of higher crude oil prices and the negative impacts of higher planned and unplanned downtime on refinery production volumes at the company s three major refineries. Operating expenses were also higher in 2007. The improvement in 2006 earnings from 2005 was primarily associated with higher average refined-product margins in 2006 and the adverse effect of downtime in 2005 at refining, marketing and pipeline operations that was caused by hurricanes in the Gulf of Mexico.

Sales volumes of refined products were 1.46 million barrels per day in 2007, a decrease of 3 percent and 1 percent from 2006 and 2005, respectively. The reported sales volume for 2007 was on a different basis than 2006 and 2005 due to a change in accounting rules that became effective April 1, 2006, for certain purchase and sale (buy/sell) contracts with the same counterparty. Excluding the impact of this accounting standard, refined-product sales in 2007 decreased 1 percent from 2006 and increased about 5 percent from 2005. Branded gasoline sales volumes of 629,000 barrels per day in 2007 increased about 2 percent from 2006 and 6 percent from 2005, largely due to growth of the Texaco brand.

Refer to the Selected Operating Data table on page FS-l0 for a three-year comparative of sales volumes of gasoline and other refined products and refinery-input volumes. Refer also to Note 13, Accounting for Buy/Sell Contracts, on page FS-42 for a discussion of the accounting for purchase and sale contracts with the same counterparty.

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Millions of dollars	**2007**	2006	2005
Income*	**$ 2,536**	$ 2,035	$ 1,786
*Includes Foreign Currency Effects:	**$ 62**	$ 98	$(24)

International downstream income of $2.5 billion in 2007 increased about $500 million from 2006 and $750 million from 2005. Results for 2007 included gains of approximately $1 billion on the sale of assets, including an interest in a refinery and marketing assets in the Benelux region of Europe. Margins on the sale of refined products in 2007 were up slightly from the prior year. Operating expenses were higher, and earnings from the company s shipping operations were lower. The increase in earnings in 2006 compared with 2005 was associated mainly with the benefit of higher refined-product sales margins in the Asia-Pacific area and Canada and improved results from crude-oil and refined-product trading activities.

Refined-product sales volumes were 2.03 million barrels per day in 2007, about 5 percent and 10 percent lower than 2006 and 2005, respectively, due largely to the impact of asset sales and the accounting-standard change for buy/sell contracts. Excluding the accounting change, sales decreased about 4 percent and 5 percent from 2006 and 2005, respectively.

Refer to the Selected Operating Data table on page FS-10 for a three-year comparative of sales volumes of gasoline and other refined products and refinery-input volumes. Refer also to Note 13, Accounting for Buy/Sell Contracts, on page FS-42 for a discussion of the accounting for purchase and sale contracts with the same counterparty.

Chemicals

Millions of dollars	**2007**	2006	2005
Income*	**$ 396**	$ 539	$ 298
*Includes Foreign Currency Effects:	**$ (3)**	$ (8)	$

The chemicals segment includes the company s Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem). In 2007, earnings were $396 million, compared with $539 million and $298 million in 2006 and 2005, respectively. Between 2006 and 2007, the benefit of improved margins on sales of lubricants and fuel additives by Oronite was more than offset by the effect of lower margins on the sale of commodity chemicals by CPChem. In 2006, earnings of $539 million increased about $240 million from 2005 due to higher margins for commodity chemicals at CPChem and for fuel and lubricant additives at Oronite.

All Other

Millions of dollars	**2007**	2006	2005
Net Charges*	**$ (26)**	$ (516)	$ (689)
*Includes Foreign Currency Effects:	**$ 6**	$ 62	(51)

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, and the company s interest in Dynegy prior to its sale in May 2007.

Net charges of $26 million in 2007 decreased $490 million from 2006. Results in 2007 included a $680 million gain on the sale of the company s investment in Dynegy common stock and a loss of approximately $175 million associated with the early redemption of Texaco Capital Inc. bonds. Excluding these items and the effects of foreign currency, net charges decreased about $40 million between periods.

Net charges of $516 million in 2006 decreased $173 million from $689 million in 2005. Excluding the effects of foreign currency, net charges declined $60 million between periods, primarily due to higher interest income and lower interest expense in 2006.

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Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2007**	2006	2005
Sales and other operating revenues	**$ 214,091**	$ 204,892	$ 193,641

Sales and other operating revenues in 2007 increased over 2006 due primarily to higher prices for crude oil, natural gas, natural gas liquids and refined products, partially offset by lower sales volumes. The increase in 2006 from 2005 was primarily due to higher prices for refined products. The higher revenues in 2006 were net of an impact from a change in the accounting for buy/sell contracts, as described in Note 13 on page FS-42.

Millions of dollars	**2007**	2006	2005
Income from equity affiliates	**$ 4,144**	$ 4,255	$ 3,731

Lower income from equity affiliates in 2007 was mainly due to a decline in earnings from CPChem, Dynegy (sold in May 2007) and downstream affiliates in the Asia-Pacific area. Partially offsetting these declines were improved results for Tengizchevroil (TCO) and income for a full year from Petroboscan, which was converted from an operating service agreement to a joint-stock company in October 2006. The increase between 2005 and 2006 was primarily due to improved results for TCO and CPChem. Refer to Note 11, beginning on page FS-40, for a discussion of Chevron s investment in affiliated companies.

Millions of dollars	**2007**	2006	2005
Other income	**$ 2,669**	$ 971	$ 828

Other income of nearly $2.7 billion in 2007 included the net of gains totaling $1.7 billion from the sale of downstream assets in the Benelux countries and the company s investment in Dynegy and a loss of approximately $245 million on the early redemption of Texaco debt. Interest income was approximately $600 million, $600 million and $400 million in 2007, 2006 and 2005, respectively. Foreign currency losses were $352 million, $260 million and $60 million in the corresponding years.

Millions of dollars	**2007**	2006	2005
Purchased crude oil and products	**$ 133,309**	$ 128,151	$ 127,968

Crude oil and product purchases in 2007 increased from 2006 due to higher prices for crude oil, natural gas, natural gas liquids and refined products. Crude oil and product purchases in 2006 increased from 2005 on higher prices for crude oil and refined products and the inclusion of Unocal-related amounts for the full year 2006 vs. five months in 2005. The increase was mitigated by the effect of the accounting change in April 2006 for buy/sell contracts.

Millions of dollars	**2007**	2006	2005
Operating, selling, general and administrative expenses	**$ 22,858**	$ 19,717	$ 17,019

Operating, selling, general and administrative expenses in 2007 increased 16 percent from a year earlier. Expenses were higher in a number of categories, with the largest increases recorded for the cost of employee payroll and contract labor. Total expenses increased in 2006 from 2005 due mainly to the inclusion of former-Unocal expenses for the full year 2006. Besides this effect, expenses were higher in 2006 for labor, transportation, and uninsured costs associated with the hurricanes in 2005.

Millions of dollars	**2007**	2006	2005
Exploration expense	**$ 1,323**	$ 1,364	$ 743

Exploration expenses in 2007 declined from 2006 mainly due to lower amounts for well write-offs and geological and geophysical costs for operations outside the United States. Expenses increased in 2006 from 2005 due to higher amounts for well write-offs and geological and geophysical costs for operations outside the United States, as well as the inclusion of Unocal-related amounts for the full year 2006.

Millions of dollars	**2007**	2006	2005
Depreciation, depletion and amortization	**$ 8,708**	$ 7,506	$ 5,913

Depreciation, depletion and amortization expenses increased from 2005 through 2007, reflecting an increase in charges related to asset write-downs and higher depreciation rates for certain crude oil and natural gas producing fields worldwide and the inclusion of Unocal-related amounts beginning in August 2005.

Millions of dollars	**2007**	2006	2005
Taxes other than on income	**$ 22,266**	$ 20,883	$ 20,782

Taxes other than on income increased in 2007 from a year earlier due to higher duties in the company s U.K. downstream operations. Taxes other than on income were essentially unchanged in 2006 from 2005, with the effect of higher U.S. refined product sales being offset by lower sales volumes subject to duties in the company s European downstream operations.

Millions of dollars	**2007**	2006	2005
Interest and debt expense	**$ 166**	$ 451	$ 482

Interest and debt expense in 2007 decreased from 2006 primarily due to lower average debt balances and higher amounts of interest capitalized. The decrease in 2006 vs. 2005 was mainly due to lower average debt balances and an increase in the amount of interest capitalized, partially offset by higher average interest rates on commercial paper and other variable-rate debt.

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Financial Condition and Results of Operations

Millions of dollars	**2007**	2006	2005
Income tax expense	**$ 13,479**	$ 14,838	$ 11,098

Effective income tax rates were 42 percent in 2007, 46 percent in 2006 and 44 percent in 2005. Rates were lower in 2007 compared with the prior year due mainly to the impact of nonrecurring items, including asset sales in 2007 and the absence of 2006 charges related to a tax-law change that increased tax rates on upstream operations in the U.K. North Sea and the settlement of a tax claim in Venezuela. The higher tax rate in 2006 compared with 2005 also reflected these nonrecurring charges in 2006. Refer also to the discussion of income taxes in Note 15 beginning on page FS-43.

Selected Operating Data[1,2]

	2007	2006	2005
U.S. Upstream[3]			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**460**	462	455
Net Natural Gas Production (MMCFPD)[4]	**1,699**	1,810	1,634
Net Oil-Equivalent Production (MBOEPD)	**743**	763	727
Sales of Natural Gas (MMCFPD)	**7,624**	7,051	5,449
Sales of Natural Gas Liquids (MBPD)	**160**	124	151
Revenues From Net Production			
Liquids ($/Bbl)	**$ 63.16**	$ 56.66	$ 46.97
Natural Gas ($/MCF)	**$ 6.12**	$ 6.29	$ 7.43
International Upstream[3]			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**1,296**	1,270	1,214
Net Natural Gas Production (MMCFPD)[4]	**3,320**	3,146	2,599
Net Oil-Equivalent Production (MBOEPD)[5]	**1,876**	1,904	1,790
Sales Natural Gas (MMCFPD)	**3,792**	3,478	2,450
Sales Natural Gas Liquids (MBPD)	**118**	102	120
Revenues From Liftings			
Liquids ($/Bbl)	**$ 65.01**	$ 57.65	$ 47.59
Natural Gas ($/MCF)	**$ 3.90**	$ 3.73	$ 3.19
U.S. and International Upstream[3]			
Net Oil-Equivalent Production Including Other Produced Volumes (MBOEPD)[4,5]			
United States	**743**	763	727
International	**1,876**	1,904	1,790

Total	**2,619**	2,667	2,517
U.S. Downstream			
Gasoline Sales (MBPD)[6]	**728**	712	709
Other Refined Product Sales (MBPD)	**729**	782	764
Total (MBPD)[7]	**1,457**	1,494	1,473
Refinery Input (MBPD)	**812**	939	845
International Downstream			
Gasoline Sales (MBPD)[6]	**581**	595	662
Other Refined Product Sales (MBPD)	**1,446**	1,532	1,590
Total (MBPD)[7,8]	**2,027**	2,127	2,252
Refinery Input (MBPD)	**1,021**	1,050	1,038

[1] Includes equity in 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 gas = 1 barrel of oil.
[3] Includes net production beginning August 2005, for properties associated with acquisition of Unocal.
[4] Includes natural gas consumed in operations (MMCFPD):

United States	**65**	56	48
International	**433**	419	356

[5] Includes other produced volumes (MBPD):

Athabasca Oil Sands Net	**27**	27	32
Boscan Operating Service Agreement		82	111
	27	109	143

[6] Includes branded and unbranded gasoline.
[7] Includes volumes for buy/sell contracts (MBPD):

United States		26	88
International		24	129

[8] Includes sales of affiliates (MBPD): **492** 492 498

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Liquidity and Capital Resources

Cash, cash equivalents and marketable securities Total balances were $8.1 billion and $11.4 billion at December 31, 2007 and 2006, respectively. Cash provided by operating activities in 2007 was $25.0 billion, compared with $24.3 billion in 2006 and $20.1 billion in 2005.

Cash provided by operating activities was net of contributions to employee pension plans of $300 million, $400 million and $1.0 billion in 2007, 2006 and 2005, respectively. Cash provided by investing activities included proceeds from asset sales of $3.3 billion in 2007, $1.0 billion in 2006 and $2.7 billion in 2005.

Cash provided by operating activities and asset sales during 2007 was sufficient to fund the company s $17.7 billion capital and exploratory program, pay $4.8 billion of dividends to stockholders and repay approximately $3.7 billion of debt.

Restricted cash of $799 million associated with capital-investment projects at the company s Pascagoula, Mississippi, refinery and Angola liquefied natural gas project was invested in short-term marketable securities and reclassified from cash equivalents to a long-term asset on the Consolidated Balance Sheet.

Dividends The company paid dividends of approximately $4.8 billion in 2007, $4.4 billion in 2006 and $3.8 billion in 2005. In April 2007, the company increased its quarterly common stock dividend by 11.5 percent to 58 cents per share.

Debt, capital lease and minority interest obligations Total debt and capital lease balances were $7.2 billion at December 31, 2007, down from $9.8 billion at year-end 2006. The company also had minority interest obligations of $204 million, down from $209 million at December 31, 2006.

The $2.6 billion reduction in total debt and capital lease obligations during 2007 included the early redemption and maturity of individual debt issues. In February, $144 million of Texaco Capital Inc. bonds matured. In the second and fourth quarters, the company redeemed approximately $809 million and $65 million, respectively of Texaco Capital Inc.

debt and recognized an after-tax loss of approximately $175 million. In August, $2 billion of Chevron Canada Funding Company bonds matured. In December, the company issued a $650 million tax exempt Mississippi Gulf Opportunity Zone bond to fund an upgrade project at the company s refinery in Pascagoula, Mississippi. Commercial paper balances at the end of 2007 declined approximately $450 million from $3.5 billion at year-end 2006. In February 2008, $750 million of Chevron Canada Funding Company bonds matured.

The company s debt and capital lease obligations due within one year, consisting primarily of commercial paper and the current portion of long-term debt, totaled $5.5 billion at December 31, 2007, down from $6.6 billion at year-end 2006. Of these amounts, $4.4 billion and $4.5 billion were reclassified to long-term at the end of each period, respectively. At year-end 2007, settlement of these obligations was not expected to require the use of working capital within one year, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

At year-end 2007, the company had $5 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and also can 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 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, 2007.

In March 2007, the company filed with the Securities and Exchange Commission (SEC) an automatic registration statement that expires in March 2010. This registration statement is for an unspecified amount of non-convertible debt securities issued or guaranteed by the company. At the same time, the company withdrew three shelf registration statements on file with the SEC that permitted the issuance of up to $3.8 billion of debt securities.

At December 31, 2007, the company had outstanding public bonds issued by Chevron Corporation Profit Sharing/Savings Plan Trust Fund, Chevron Canada Funding Company (formerly ChevronTexaco Capital Company), Texaco Capital Inc. and Union Oil Company of California. All of these securities are guaranteed by Chevron Corporation and are rated AA by Standard and Poor s Corporation and Aal by Moody s Investors Service. The rating by Moody s reflects an upgrade in December from Aa2. The company s U.S. commercial paper is rated A-l+ 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-spending program and cash that may be generated from asset dispositions. The company believes that it has substantial borrowing capacity to meet unanticipated cash requirements and that during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, it has the flexibility to increase borrowings and/or modify capital-spending plans to continue paying the common stock dividend and maintain the company s high-quality debt ratings.

Common stock repurchase program A $5 billion stock repurchase program initiated in December 2006 was completed in September 2007. During 2007, about 61.5 million common shares were acquired under this program at a total cost of $4.9 billion. Upon completion of this program, the company authorized the acquisition of up to $15 billion of additional common shares from time to time at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. The program is for a period of up to three years and may be discontinued at any time. As of December 31, 2007, 23.5 million shares had been acquired under the new program for $2.1 billion. Purchases through mid-February 2008 increased the total shares acquired to 34.2 million at a cost of approximately $3.0 billion.

Capital and exploratory expenditures Total reported expenditures for 2007 were $20 billion, including $2.3 billion for the company s share of affiliates expenditures, which did not require cash outlays by the company. In 2006 and 2005, expenditures were $16.6 billion and $11.1 billion, respectively, including the company s share of affiliates expenditures of $1.9 billion and $1.7 billion in the corresponding periods. The 2005 amount excludes $17.3 billion for the acquisition of Unocal Corporation.

Of the $20 billion in expenditures for 2007, about three-fourths, or $15.5 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2006 and 2005. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the three years, reflecting the company s continuing focus on opportunities that are available outside the United States.

In 2008, the company estimates capital and exploratory expenditures will be 15 percent higher at $22.9 billion, including $2.6 billion of spending by affiliates. About three-fourths of the total, or $17.5 billion, is budgeted for exploration and production activities, with $12.7 billion of this amount outside the United States. Spending in 2008 is primarily targeted for exploratory prospects in the deepwater Gulf of Mexico and western Africa and major development projects in Angola, Australia, Brazil, Indonesia, Kazakhstan, Nigeria, Thailand, the deepwater Gulf of Mexico, the Piceance Basin in Colorado and an oil sands project in Canada.

Worldwide downstream spending in 2008 is estimated at $4.1 billion, with about $2.3 billion for projects in the United States. Capital projects include upgrades to refineries in the United States and South Korea and construction of gas-to-liquids facilities in support of associated upstream projects.

Investments in chemicals, technology and other corporate businesses in 2008 are budgeted at $1.3 billion. Technology investments include projects related to unconventional hydrocarbons technologies, oil and gas reservoir management and gas-fired and renewable power generation.

Capital and Exploratory Expenditures

			2007			2006			2005
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total

Upstream									
Exploration and Production	**$ 4,558**	**$ 10,980**	**$ 15,538**	$ 4,123	$ 8,696	$ 12,819	$ 2,450	$ 5,939	$ 8,389
Downstream									
Refining, Marketing and Transportation	**1,576**	**1,867**	**3,443**	1,176	1,999	3,175	818	1,332	2,150
Chemicals	**218**	**53**	**271**	146	54	200	108	43	151
All Other	**768**	**6**	**774**	403	14	417	329	44	373
Total	**$ 7,120**	**$ 12,906**	**$ 20,026**	$ 5,848	$ 10,763	$ 16,611	$ 3,705	$ 7,358	$ 11,063
Total, Excluding Equity in Affiliates	**$ 6,900**	**$ 10,790**	**$ 17,690**	$ 5,642	$ 9,050	$ 14,692	$ 3,522	$ 5,860	$ 9,382

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Pension Obligations In 2007, the company s pension plan contributions were $317 million (approximately $78 million to the U.S. plans). The company estimates contributions in 2008 will be approximately $500 million. Actual contribution amounts are dependent upon plan-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. Refer also to the discussion of pension accounting in Critical Accounting Estimates and Assumptions, beginning on page FS-18.

Financial Ratios

Financial Ratios

	At December 31		
	2007	2006	2005
Current Ratio	**1.2**	1.3	1.4
Interest Coverage Ratio	**69.2**	53.5	47.5
Total Debt/Total Debt-Plus-Equity	**8.6%**	12.5%	17.0%

Current Ratio current assets divided by current liabilities. 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 2007, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $7 billion.

Interest Coverage Ratio income before income tax expense, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs. The company s interest coverage ratio was higher between 2007 and 2006 and between 2006 and 2005, primarily due to higher before-tax income and lower average debt balances in each of the subsequent years.

Debt Ratio total debt as a percentage of total debt plus equity. The progressive decrease between 2005 and 2007, was due to lower average debt levels and higher stockholders equity balances.

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

Direct Guarantee

Millions of dollars		Commitment Expiration by Period			
	Total	2008	2009-2011	2012	After 2012
Guarantee of non-consolidated affiliate or joint-venture obligation	$ 613	$	$	$ 38	$ 575

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 reduce 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 carries 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 2007, 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 must be asserted no later than February 2009 for Equilon indemnities and 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 has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described above 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. Under the indemnification agreement, the company s liability is unlimited until April 2022, when the indemnification expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of $200 million, which had not been reached as of December 31, 2007.

Securitization During 2007, the company completed the sale of its U.S. proprietary consumer credit card business and related receivables. This transaction included terminating the qualifying Special Purpose Entity (SPE) that was used to securitize associated retail accounts receivable.

Through the use of another qualifying SPE, the company had $675 million of securitized trade accounts receivable related to its downstream business as of December 31, 2007. This arrangement has the effect of accelerating Chevron s collection of the securitized amounts. Chevron s total estimated financial exposure under this securitization at December 31, 2007, was $65 million. In the event that the SPE experiences major defaults in the collection of receivables, Chevron believes that it would have no additional loss exposure connected with third-party investments in this securitization.

Minority Interests The company has commitments of $204 million related to minority interests in subsidiary companies.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating 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: 2008 $4.7 billion; 2009 $3.3 billion; 2010 $3.3 billion; 2011 $1.9 billion; 2012 $1.3 billion; 2013 and after $4.9 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3.7 billion in 2007, $3.0 billion in 2006 and $2.1 billion in 2005.

The following table summarizes the company s significant contractual obligations:

Contractual Obligations

Millions of dollars			Payments Due by Period		
	Total	2008	2009-2011	2012	After 2012
On Balance Sheet:[1]					
Short-Term Debt[2]	$ 1,162	$ 1,162	$	$	$
Long-Term Debt[2]	5,664		4,926	33	705
Noncancelable Capital Lease Obligations	406		193	61	152
Interest	3,950	360	899	292	2,399
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	3,167	513	1,255	293	1,106
Throughput and Take-or-Pay Agreements	13,118	3,699	4,783	618	4,018
Other Unconditional Purchase Obligations[3]	6,300	988	3,779	653	880

[1] 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 due. 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.

[2] $4.4. 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 2009-2011 period.

[3] 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 liquefied natural gas and related natural gas liquids per year. Volumes and prices associated with these purchase obligations are neither fixed nor determinable.

Financial and Derivative Instruments

No material change in market risk occurred between 2006 and 2007 for the financial and derivative instruments discussed below. The hypothetical variances used in this section were selected for illustrative purposes only and do not represent the company s estimation of 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 1, Item 1A, of the company s 2007 Annual Report on Form 10-K.

Commodity Derivative 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 this activity were not material to the company s financial position, net income or cash flows in 2007.

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

The derivative instruments used in the company s risk management and trading activities consist mainly of futures, options, and swap contracts traded on the NYMEX (New York Mercantile Exchange) and on electronic platforms of ICE (Inter-Continental Exchange) and GLOBEX (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.

Effective with 2007 year-end reporting, the company changed the model used to quantify information about market risk for its commodity derivatives from a sensitivity analysis approach to Value-at-Risk (VaR). The major reason for the change is that VaR allows estimation of a portfolio s aggregate market risk exposure and takes into account correlations between trading assets. Therefore, it reflects risk reduction due to diversification or hedging activities. Most of the company s market positions are time and commodity spreads, and the company believes that VaR is a more accurate tool to measure this type of exposure than the sensitivity analysis model. The company fully developed and tested its VaR model during 2007.

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 distribution and constructing a full distribution of a potential portfolio s values.

The VaR model utilizes an exponentially-weighted moving average for computing historical volatilities and correlations, a 95 percent confidence level, and 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 table below presents 95 percent/one-day VaR for each of the company s primary risk exposures in the area of commodity derivative instruments at December 31, 2007:

Millions of dollars	**2007**
Crude Oil	**$ 29**
Natural Gas	**3**
Refined Products	**23**

Sensitivity analysis for the company s open commodity derivative instruments at December 31, 2007, and December 31, 2006, based on a hypothetical 10 percent increase in commodity prices, is provided in the following table:

Incremental Increase (Decrease) in Fair Value of Open Commodity Derivative Contracts Assuming a Hypothetical Increase in Year-End Commodity Prices of 10 Percent

Millions of dollars	**2007**	2006
Crude Oil	**$ (113)**	$ 4
Natural Gas	**14**	10

Refined Products	**(96)**	(30)

The same hypothetical decrease in prices of these commodities would result in approximately the same opposite effects on the fair values of the contracts. The hypothetical effect on these contracts was estimated by calculating the fair value of the contracts as the difference between the hypothetical and current market prices multiplied by the contract amounts.

The change in the amounts between years in the table above for crude oil and refined products is associated with an increase in commodity prices, volumes hedged and the use of longer-term contracts.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The aggregate effect of a hypothetical 10 percent increase in the value of the U.S. dollar at year-end 2007 would be a reduction in the fair value of the foreign exchange contracts of approximately $75 million. The effect would be the opposite for a hypothetical 10 percent decrease in the value of the U.S. dollar at year-end 2007.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company s fixed-rate debt are accounted for as fair value hedges. Interest rate swaps related to floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2007, the company had no interest-rate swaps on floating-rate debt. At year-end 2007, the weighted average maturity of receive fixed interest rate swaps was less than one year. A hypothetical increase or decrease of 10 basis points in fixed interest rates would have a *de minimis* impact on the fair value of the receive fixed 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. Long-term purchase agreements are in place with the company s refining affiliate in Thailand. Refer to page FS-5 for further discussion. Management believes the foregoing agreements and others 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. The company is a party to 88 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepages of MTBE into groundwater. Chevron has agreed in principle to a tentative settlement of 60 pending lawsuits and claims. The terms of this agreement, which must be approved by a number of parties, including the court, are confidential and not material to the company s results of operations, liquidity or financial position.

Resolution of remaining 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 tentative settlement of the referenced 60 lawsuits did not set any precedents related to standards of liability to be used to judge the merits of the claims, corrective measures required or monetary damages to be assessed for the remaining lawsuits and claims or future lawsuits and claims. As a result, the company s ultimate exposure related to pending lawsuits and claims is not currently 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.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal s undisclosed and pending patents. Eleven lawsuits were consolidated in U.S. District Court for the Central District of California, where a class action has been certified, and three were consolidated in a state court action. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys fees, and interest on behalf of an alleged class of consumers who

purchased summertime RFG in California from January 1995 through August 2005. The parties have reached a tentative agreement to resolve all of the above matters in an amount that is not material to the company s results of operations, liquidity or financial position. The terms of this agreement are confidential, and subject to further negotiation and approval, including by the courts.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations 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.

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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	**2007**	2006	2005
Balance at January 1	**$ 1,441**	$ 1,469	$ 1,047
Net Additions	**562**	366	731
Expenditures	**(464)**	(394)	(309)
Balance at December 31	**$ 1,539**	$ 1,441	$ 1,469

Included in the $1,539 million year-end 2007 reserve balance were remediation activities of 240 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 2007 was $123 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 consolidated financial position or liquidity.

Of the remaining year-end 2007 environmental reserves balance of $1,416 million, $864 million related to approximately 2,000 sites for the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining $552 million was associated with various sites in international downstream ($146 million), upstream ($267 million), chemicals ($105 million) and other ($34 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 2007 had a recorded liability that was material to the company s financial position, results of operations 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 accounts for asset retirement obligations in accordance with Financial Accounting Standards Board Statement (FASB) No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). Under FAS 143, the fair value of a liability for an asset retirement obligation is recorded when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. The liability balance of approximately $8.3 billion for asset retirement obligations at year-end 2007 related primarily to upstream and mining 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 23, beginning on page FS-57, related to FAS 143 and the company s adoption in 2005 of FASB Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations An Interpretation of FASB*

Statement No. 143 (FIN 47), and the discussion of Environmental Matters on page FS-18.

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-43 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, 2007, the company had approximately $1.7 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $421 million from 2006 and an increase of $551 million from 2005.

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 $1.7 billion of suspended wells at year-end 2007 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page FS-47, for additional discussion of suspended wells.

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Equity Redetermination For oil and 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 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 2007 at approximately $2.7 billion for its consolidated companies. Included in these expenditures were approximately $900 million of environmental capital expenditures and $1.8 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites and the abandonment and restoration of sites.

For 2008, total worldwide environmental capital expenditures are estimated at $1.9 billion. These capital costs are 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 or assumptions is according to the disclosure guidelines of the Securities and Exchange Commission (SEC), wherein:

1. the nature of the estimates or 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.

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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 that require ... geological and engineering data (that) demonstrate with reasonable certainty (reserves) to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Refer to Table V, Reserve Quantity Information, beginning on page FS-66, for the changes in these estimates for the three years ending December 31, 2007, and to Table VII, Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves on page FS-74 for estimates of proved-reserve values for each of the three years ending December 31, 2007, which were based on year-end prices at the time. 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-20, 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 20, beginning on page FS-48, includes information on the funded status of the company s pension and OPEB plans at the end of 2007 and 2006, the components of pension and OPEB expense for the three years ending December 31, 2007, and the underlying assumptions for those periods.

Pension and OPEB expense is recorded on the Consolidated Statement of Income in Operating expenses or Selling, general and administrative expenses and applies to all business segments. The year-end 2007 and 2006 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 funded status of overfunded pension plans is recorded as a long-term asset in Deferred charges and other assets. The funded status of underfunded or unfunded pension and OPEB plans is recorded in Accrued liabilities or Reserves for employee benefit plans. Amounts yet to be recognized as components of pension or OPEB expense are recorded in Accumulated other comprehensive income.

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 67 percent of the company s pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2007, actual asset returns averaged 8.7 percent for this plan.

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 the measurement date 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, 2007, the company selected a 6.3 percent discount rate for the major U.S. pension and postretirement plans. This rate was selected based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2007. The discount rates at the end of 2006 and 2005 were 5.8 percent and 5.5 percent, respectively.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2007 was $620 million. 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 2007 by approximately $70

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million. A 1 percent increase in the discount rate for this same plan, which accounted for about 60 percent of the companywide pension obligation, would have reduced total pension plan expense for 2007 by approximately $155 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan recorded on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2007, for underfunded plans was approximately $1.7 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 $250 million, which would have increased the plan s over-funded status from approximately $160 million to $410 million. 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 2007, the company s pension plan contributions were $317 million (including $78 million to the U.S. plans). In 2008, the company estimates contributions will be approximately $500 million. Actual contribution amounts are dependent upon plan-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 2007 was $233 million and the total liability, which reflected the underfunded status of the plans at the end of 2007, was $2.9 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2007, a 1 percent increase in the discount rate for the company s primary U.S. OPEB plan, which accounted for about 75 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $20 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 87 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2007 by approximately $60 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. The cap becomes effective in the year of retirement for pre-Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre-Medicare-eligible employees retiring before that date and all Medicare-eligible retirees. 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 2008 and gradually drop to 5 percent for 2014 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2007, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for about 87 percent of the companywide OPEB liabilities, would have increased OPEB expense $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 included in actuarial gain/loss and unamortized amounts have been reflected in Accumulated other comprehensive loss on the Consolidated Balance Sheet. Refer to Note 20, beginning on page FS-48, for information on the $3.3 billion of before-tax actuarial losses recorded by the company as of December 31, 2007; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2008.

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.

No major individual impairments of PP&E were recorded for the three years ending December 31, 2007. An estimate as to the sensitivity to 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 that no 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.

Business Combinations Purchase-Price Allocation Accounting for business combinations requires the allocation of the company s purchase price to the various assets and liabilities of the acquired business at their respective fair values. The company uses all available information to make these fair value determinations, and for major acquisitions, may hire an independent appraisal firm to assist in making fair value estimates. In some instances, assumptions with respect to the timing and amount of future revenues and expenses associated with an asset might have to be used in determining its fair value. Actual timing and amount of net cash flows from revenues and expenses related to that asset over time may differ materially from those initial estimates, and if the timing is delayed significantly or if the net cash flows decline significantly, the asset could become impaired.

Goodwill Goodwill resulting from a business combination is not subject to amortization. As required by FASB Statement No. 142, *Goodwill and Other Intangible Assets,* 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 records 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-43. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, and environmental remediation and tax matters for the three years ended December 31, 2007.

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

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which became effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 does not require any new fair value measurements but applies to assets and liabilities that are required to be recorded at fair value under other accounting standards. The implementation of FAS 157 did not have a material effect on the company s results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Its Related Interpretive Accounting Pronouncements That Address Leasing Transactions (FSP 157-1) In February 2008, the FASB issued FSP 157-1, which became effective for the company on January 1, 2008. This FSP excludes FASB Statement No. 13, Accounting for Leases, and its related interpretive accounting pronouncements from the provisions of FAS 157. Implementation of this standard did not have a material effect on the company s results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-2, Effective Date of FASB Statement No. 157 (FSP 157-2) In February 2008, the FASB issued FSP 157-2, which delays the company s January 1, 2008, effective date of FAS 157 for all nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. Implementation of this standard did not have a material effect on the company s results of operations or consolidated financial position.

FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 (FAS 159) In February 2007, the FASB issued FAS 159, which became effective for the company on January 1, 2008. This standard permits companies to choose to measure many financial instruments and certain other items at fair value and report unrealized gains and losses in earnings. Such accounting is optional and is generally to be applied instrument by instrument. The implementation of FAS 159 did not have a material effect on the company s results of operations or consolidated financial position.

FASB Statement No. 141 (revised 2007), Business Combinations (FAS 141-R) In December 2007, the FASB issued FAS 141-R, which will become effective for business combination transactions having an acquisition date on or after January 1, 2009. This standard requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date to be measured at their respective fair values. The Statement requires acquisition-related costs, as well as restructuring costs the acquirer expects to incur for which it is not obligated at acquisition date, to be recorded against income rather than included in purchase-price determination. It also requires recognition of contingent arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in income.

FASB Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (FAS 160) The FASB issued FAS 160 in December 2007, which will become effective for the company January 1, 2009, with retroactive adoption of the Statement s presentation and disclosure requirements for existing minority interests. This standard will require ownership interests in subsidiaries held by parties other than the parent to be presented within the equity section of the consolidated statement of financial position but separate from the parent s equity. It will also require the amount of consolidated net income attributable to the parent and the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement. Certain changes in a parent s ownership interest are to be accounted for as equity transactions and when a subsidiary is deconsolidated, any noncontrolling equity investment in the former subsidiary is to be initially measured at fair value. The company does not anticipate the implementation of FAS 160 will significantly change the presentation of its consolidated income statement or consolidated balance sheet.

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Quarterly Results and Stock Market Data
Unaudited

Millions of dollars, except per-share amounts	**4th Q**	**3rd Q**	**2nd Q**	**2007 1st Q**	4th Q	3rd Q	2nd Q	2006 1st Q
Revenues and Other Income								
Sales and other operating revenues[1,2]	**$ 59,900**	**$ 53,545**	**$ 54,344**	**$ 46,302**	$ 46,238	$ 52,977	$ 52,153	$ 53,524
Income from equity affiliates	**1,153**	**1,160**	**894**	**937**	1,079	1,080	1,113	983
Other income	**357**	**468**	**856**	**988**	429	155	270	117
Total Revenues and Other Income	**61,410**	**55,173**	**56,094**	**48,227**	47,746	54,212	53,536	54,624
Costs and Other Deductions								
Purchased crude oil and products[2]	**38,056**	**33,988**	**33,138**	**28,127**	27,658	32,076	32,747	35,670
Operating expenses	**4,798**	**4,397**	**4,124**	**3,613**	4,092	3,650	3,835	3,047
Selling, general and administrative expenses	**1,833**	**1,446**	**1,516**	**1,131**	1,203	1,428	1,207	1,255
Exploration expenses	**449**	**295**	**273**	**306**	547	284	265	268
Depreciation, depletion and amortization	**2,094**	**2,495**	**2,156**	**1,963**	1,988	1,923	1,807	1,788
Taxes other than on income[1]	**5,560**	**5,538**	**5,743**	**5,425**	5,533	5,403	5,153	4,794
Interest and debt expense	**7**	**22**	**63**	**74**	92	104	121	134
Minority interests	**35**	**25**	**19**	**28**	2	20	22	26
Total Costs and Other Deductions	**52,832**	**48,206**	**47,032**	**40,667**	41,115	44,888	45,157	46,982
Income Before Income Tax Expense	**8,578**	**6,967**	**9,062**	**7,560**	6,631	9,324	8,379	7,642
Income Tax Expense	**3,703**	**3,249**	**3,682**	**2,845**	2,859	4,307	4,026	3,646
Net Income	**$ 4,875**	**$ 3,718**	**$ 5,380**	**$ 4,715**	$ 3,772	$ 5,017	$ 4,353	$ 3,996
Per-Share of Common Stock								
Net Income								
Basic	**$ 2.34**	**$ 1.77**	**$ 2.52**	**$ 2.20**	$ 1.75	$ 2.30	$ 1.98	$ 1.81
Diluted	**$ 2.32**	**$ 1.75**	**$ 2.52**	**$ 2.18**	$ 1.74	$ 2.29	$ 1.97	$ 1.80
Dividends	**$ 0.58**	**$ 0.58**	**$ 0.58**	**$ 0.52**	$ 0.52	$ 0.52	$ 0.52	$ 0.45
Common Stock Price Range High[3]	**$ 94.86**	**$ 94.84**	**$ 84.24**	**$ 74.95**	$ 75.97	$ 67.85	$ 62.88	$ 62.21
Low[3]	**$ 83.79**	**$ 80.76**	**$ 74.83**	**$ 66.43**	$ 62.94	$ 60.88	$ 56.78	$ 54.08
[1] Includes excise, value-added and similar taxes:	**$2,548**	**$2,550**	**$2,609**	**$2,414**	$2,498	$2,522	$2,416	$2,115
[2] Includes amounts for buy/sell contracts:	**$**	**$**	**$**	**$**	$	$	$	$6,725

[3] End of day price.

The company s common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 22, 2008, stockholders of record numbered approximately 214,000. 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, 2007.

The effectiveness of the company s internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

David J. O Reilly	Stephen J. Crowe	Mark A. Humphrey
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 28, 2008

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, shareholders equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2007, and December 31, 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, 2007, 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 Controls 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 misstatements 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.

As discussed in Note 13 to the Consolidated Financial Statements, the Company changed its method of accounting for buy/sell contracts on April 1, 2006.

As discussed in Note 15 to the Consolidated Financial Statements, the Company changed its method of accounting for uncertain income tax positions on January 1, 2007.

As discussed in Note 20 to the Consolidated Financial Statements, the Company changed its method of accounting for defined benefit pension and other postretirement plans on December 31, 2006.

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 28, 2008

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

		Year ended December 31	
	2007	2006	2005
Revenues and Other Income			
Sales and other operating revenues[1,2]	**$ 214,091**	$ 204,892	$ 193,641
Income from equity affiliates	**4,144**	4,255	3,731
Other income	**2,669**	971	828
Total Revenues and Other Income	**220,904**	210,118	198,200
Costs and Other Deductions			
Purchased crude oil and products[2]	**133,309**	128,151	127,968
Operating expenses	**16,932**	14,624	12,191
Selling, general and administrative expenses	**5,926**	5,093	4,828
Exploration expenses	**1,323**	1,364	743
Depreciation, depletion and amortization	**8,708**	7,506	5,913
Taxes other than on income[1]	**22,266**	20,883	20,782
Interest and debt expense	**166**	451	482
Minority interests	**107**	70	96
Total Costs and Other Deductions	**188,737**	178,142	173,003
Income Before Income Tax Expense	**32,167**	31,976	25,197
Income Tax Expense	**13,479**	14,838	11,098
Net Income	**$ 18,688**	$ 17,138	$ 14,099
Per-Share of Common Stock			
Net Income			
Basic	**$ 8.83**	$ 7.84	$ 6.58
Diluted	**$ 8.77**	$ 7.80	$ 6.54
[1] Includes excise, value-added and similar taxes.	**$ 10,121**	$ 9,551	$ 8,719
[2] Includes amounts in revenues for buy/sell contracts; associated costs are in Purchased crude oil and products. Refer also to Note 13, on page FS-42.	**$**	$ 6,725	$ 23,822

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2007	2006	2005
Net Income	**$ 18,688**	$ 17,138	$ 14,099
Currency translation adjustment			
Unrealized net change arising during period	**31**	55	(5)
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	**17**	(88)	(32)
Reclassification to net income of net realized loss	**2**		
Total	**19**	(88)	(32)
Derivatives			
Net derivatives (loss) gain on hedge transactions	**(10)**	2	(242)
Reclassification to net income of net realized loss	**7**	95	34
Income taxes on derivatives transactions	**(3)**	(30)	77
Total	**(6)**	67	(131)
Defined benefit plans			
Minimum pension liability adjustment		(88)	89
Actuarial loss			
Amortization to net income of net actuarial loss	**356**		
Actuarial gain arising during period	**530**		
Prior service cost			
Amortization to net income of net prior service credits	**(15)**		
Prior service cost arising during period	**204**		
Non-sponsored defined benefit plans	**19**		
Income taxes on defined benefit plans	**(409)**	50	(31)
Total	**685**	(38)	58
Other Comprehensive Gain (Loss), Net of Tax	**729**	(4)	(110)
Comprehensive Income	**$ 19,417**	$ 17,134	$ 13,989

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	
	2007	2006
Assets		
Cash and cash equivalents	**$ 7,362**	$ 10,493
Marketable securities	**732**	953
Accounts and notes receivable (less allowance: 2007 $165; 2006 $175)	**22,446**	17,628
Inventories:		
Crude oil and petroleum products	**4,003**	3,586
Chemicals	**290**	258
Materials, supplies and other	**1,017**	812
Total inventories	**5,310**	4,656
Prepaid expenses and other current assets	**3,527**	2,574
Total Current Assets	**39,377**	36,304
Long-term receivables, net	**2,194**	2,203
Investments and advances	**20,477**	18,552
Properties, plant and equipment, at cost	**154,084**	137,747
Less: Accumulated depreciation, depletion and amortization	**75,474**	68,889
Properties, plant and equipment, net	**78,610**	68,858
Deferred charges and other assets	**3,491**	2,088
Goodwill	**4,637**	4,623
Total Assets	**$ 148,786**	$ 132,628
Liabilities and Stockholders Equity		
Short-term debt	**$ 1,162**	$ 2,159
Accounts payable	**21,756**	16,675
Accrued liabilities	**5,275**	4,546
Federal and other taxes on income	**3,972**	3,626
Other taxes payable	**1,633**	1,403
Total Current Liabilities	**33,798**	28,409
Long-term debt	**5,664**	7,405
Capital lease obligations	**406**	274
Deferred credits and other noncurrent obligations	**15,007**	11,000
Noncurrent deferred income taxes	**12,170**	11,647
Reserves for employee benefit plans	**4,449**	4,749
Minority interests	**204**	209
Total Liabilities	**71,698**	63,693
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)		

Common stock (authorized 4,000,000,000 shares, $0.75 par value; 2,442,676,580 shares issued at December 31, 2007 and 2006)	**1,832**	1,832
Capital in excess of par value	**14,289**	14,126
Retained earnings	**82,329**	68,464
Notes receivable key employees	**(1)**	(2)
Accumulated other comprehensive loss	**(2,015)**	(2,636)
Deferred compensation and benefit plan trust	**(454)**	(454)
Treasury stock, at cost (2007 352,242,618 shares; 2006 278,118,341 shares)	**(18,892)**	(12,395)
Total Stockholders Equity	**77,088**	68,935
Total Liabilities and Stockholders Equity	**$ 148,786**	$ 132,628

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2007	2006	2005
Operating Activities			
Net income	**$ 18,688**	$ 17,138	$ 14,099
Adjustments			
Depreciation, depletion and amortization	**8,708**	7,506	5,913
Dry hole expense	**507**	520	226
Distributions less than income from equity affiliates	**(1,439)**	(979)	(1,304)
Net before-tax gains on asset retirements and sales	**(2,315)**	(229)	(134)
Net foreign currency effects	**378**	259	62
Deferred income tax provision	**261**	614	1,393
Net decrease (increase) in operating working capital	**685**	1,044	(54)
Minority interest in net income	**107**	70	96
(Increase) in long-term receivables	**(82)**	(900)	(191)
(Increase) decrease in other deferred charges	**(530)**	232	668
Cash contributions to employee pension plans	**(317)**	(449)	(1,022)
Other	**326**	(503)	353
Net Cash Provided by Operating Activities	**24,977**	24,323	20,105
Investing Activities			
Cash portion of Unocal acquisition, net of Unocal cash received			(5,934)
Capital expenditures	**(16,678)**	(13,813)	(8,701)
Repayment of loans by equity affiliates	**21**	463	57
Proceeds from asset sales	**3,338**	989	2,681
Net sales of marketable securities	**185**	142	336
Net purchases of other short-term investments	**(799)**		
Net Cash Used for Investing Activities	**(13,933)**	(12,219)	(11,561)
Financing Activities			
Net payments of short-term obligations	**(345)**	(677)	(109)
Repayments of long-term debt and other financing obligations	**(3,343)**	(2,224)	(966)
Proceeds from issuances of long-term debt	**650**		20
Cash dividends common stock	**(4,791)**	(4,396)	(3,778)
Dividends paid to minority interests	**(77)**	(60)	(98)
Net purchases of treasury shares	**(6,389)**	(4,491)	(2,597)
Redemption of preferred stock of subsidiaries			(140)
Net Cash Used for Financing Activities	**(14,295)**	(11,848)	(7,668)
Effect of Exchange Rate Changes On Cash and Cash Equivalents	**120**	194	(124)

Net Change in Cash and Cash Equivalents	**(3,131)**	450	752
Cash and Cash Equivalents at January 1	**10,493**	10,043	9,291
Cash and Cash Equivalents at December 31	**$ 7,362**	$ 10,493	$ 10,043

See accompanying Notes to the Consolidated Financial Statements.

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

	2007 Shares	2007 Amount	2006 Shares	2006 Amount	2005 Shares	2005 Amount
Preferred Stock		**$**		$		$
Common Stock						
Balance at January 1	**2,442,677**	**$ 1,832**	2,442,677	$ 1,832	2,274,032	$ 1,706
Shares issued for Unocal acquisition					168,645	126
Balance at December 31	**2,442,677**	**$ 1,832**	2,442,677	$ 1,832	2,442,677	$ 1,832
Capital in Excess of Par						
Balance at January 1		**$ 14,126**		$ 13,894		$ 4,160
Shares issued for Unocal acquisition						9,585
Treasury stock transactions		**163**		232		149
Balance at December 31		**$ 14,289**		$ 14,126		$ 13,894
Retained Earnings						
Balance at January 1		**$ 68,464**		$ 55,738		$ 45,414
Net income		**18,688**		17,138		14,099
Cash dividends on common stock		**(4,791)**		(4,396)		(3,778)
Adoption of EITF 04 6, Accounting for Stripping Costs Incurred during Production in the Mining Industry				(19)		
Adoption of FIN 48, Accounting for Uncertainty in Income Taxes		**(35)**				
Tax benefit from dividends paid on unallocated ESOP shares and other		**3**		3		3
Balance at December 31		**$ 82,329**		$ 68,464		$ 55,738
Notes Receivable Key Employees		**$ (1)**		$ (2)		$ (3)
Accumulated Other Comprehensive Loss						

Currency translation adjustment						
Balance at January 1		**$ (90)**		$ (145)		$ (140)
Change during year		**31**		55		(5)
Balance at December 31		**$ (59)**		$ (90)		$ (145)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (2,585)**		$ (344)		$ (402)
Change to defined benefit plans during year		**685**		(38)		58
Adoption of FAS 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans		**(108)**		(2,203)		
Balance at December 31		**$ (2,008)**		$ (2,585)		$ (344)
Unrealized net holding gain on securities						
Balance at January 1		**$**		$ 88		$ 120
Change during year		**19**		(88)		(32)
Balance at December 31		**$ 19**		$		$ 88
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 39**		$ (28)		$ 103
Change during year		**(6)**		67		(131)
Balance at December 31		**$ 33**		$ 39		$ (28)
Balance at December 31		**$ (2,015)**		$ (2,636)		$ (429)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ (214)**		$ (246)		$ (367)
Net reduction of ESOP debt and other				32		121
Balance at December 31		**(214)**		(214)		(246)
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240)
Balance at December 31	**14,168**	**$ (454)**	14,168	$ (454)	14,168	$ (486)
Treasury Stock at Cost						
Balance at January 1	**278,118**	**$ (12,395)**	209,990	$ (7,870)	166,912	$ (5,124)
Purchases	**85,429**	**(7,036)**	80,369	(5,033)	52,013	(3,029)

Issuances mainly employee benefit plans	**(11,304)**	**539**	(12,241)	508	(8,935)	283
Balance at December 31	**352,243**	**$ (18,892)**	278,118	$ (12,395)	209,990	$ (7,870)
Total Stockholders Equity at December 31		**$ 77,088**		$ 68,935		$ 62,676

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 Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemical operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant oil additives.

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. Subsequent recoveries in the carrying value of other investments are reported in Other comprehensive income.

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. The company s share of the affiliate s reported earnings is adjusted quarterly when appropriate to reflect the difference between these allocated values and the affiliate s historical book values.

Derivatives The majority of the company s activity in commodity derivative 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 the derivative instruments are reported in current income. For derivative instruments relating to foreign currency exposures, gains and losses are reported in current income. Interest rate swaps hedging a portion of the company s fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company s floating-rate debt are recorded at fair value on the Consolidated 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 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. The balance of the short-term investments is reported as Marketable securities and are marked-to-market, with any unrealized gains or losses included in Other comprehensive income.

Inventories Crude oil, petroleum products and chemicals are generally stated at cost, using a Last-In, First-Out (LIFO) method. In the aggregate, these costs are below market. Materials, supplies and other inventories generally are stated at average cost.

Note 1 Summary of Significant Accounting Policies Continued

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 are also 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-47, 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 the refining, marketing, transportation and chemical areas, 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.

As required under Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143), 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 23, beginning on page FS-57, 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 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 proven 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 FASB Statement No. 142, *Goodwill and Other Intangible Assets*, 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 is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and mineral producing properties,

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

Note 1 Summary of Significant Accounting Policies   Continued

a liability for an asset retirement obligation is made, following FAS 143. Refer to Note 23, beginning on page FS-57, for a discussion of FAS 143.

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 translations are currently included in 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 the currency translation adjustment in Stockholders 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 basis of the company s net working interest (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. Refer to Note 13, on page FS-42, for a discussion of the accounting for buy/sell arrangements.

Stock Options and Other Share-Based Compensation Effective July 1, 2005, the company adopted the provisions of FASB Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

Refer to Note 21, beginning on page FS-53, for a description of the company s share-based compensation plans, information related to awards granted under those plans and additional information on the company s adoption of FAS 123R.

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123R to stock options, stock appreciation rights, performance units and restricted stock units for the full year 2005.

	Year ended December 31
	2005

Net income, as reported	$ 14,099
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	81
Deduct: Total stock-based employee compensation expense determined under fair-valued-based method for awards, net of related tax effects*	(108)
Pro forma net income	$ 14,072
Net income per share:	
Basic as reported	$ 6.58
Basic pro forma	$ 6.56
Diluted as reported	$ 6.54
Diluted pro forma	$ 6.53

*Fair value determined using the Black-Scholes option-pricing model.

Note 2

Acquisition of Unocal Corporation

In August 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. The aggregate purchase price of Unocal was $17,288. The final purchase-price allocation to the assets and liabilities acquired was completed as of June 30, 2006.

The following unaudited pro forma summary presents the results of operations as if the acquisition of Unocal had occurred at the beginning of 2005:

	Year ended December 31 2005
Sales and other operating revenues	$ 198,762
Net income	14,967
Net income per share of common stock	
Basic	$ 6.68
Diluted	$ 6.64

The pro forma summary used estimates and assumptions based on information available at the time. Management believes the estimates and assumptions to be reasonable; however, actual results may have differed significantly from this pro forma financial information.

Note 3
Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2007	2006	2005
Net decrease (increase) in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	**$ (3,867)**	$ 17	$ (3,164)
Increase in inventories	**(749)**	(536)	(968)
Increase in prepaid expenses and other current assets	**(370)**	(31)	(54)
Increase in accounts payable and accrued liabilities	**4,930**	1,246	3,851
Increase in income and other taxes payable	**741**	348	281
Net decrease (increase) in operating working capital	**$ 685**	$ 1,044	$ (54)
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	**$ 203**	$ 470	$ 455
Income taxes	**$ 12,340**	$ 13,806	$ 8,875
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (1,975)**	$ (1,271)	$ (918)
Marketable securities sold	**2,160**	1,413	1,254
Net sales (purchases) of marketable securities	**$ 185**	$ 142	$ 336

The Consolidated Statement of Cash Flows does not include noncash financing and investing activities. Refer to Note 23, starting on page FS-57, for a discussion of revisions to the company s asset retirement obligations that did not involve cash receipts or payments in 2007.

In accordance with the cash-flow classification requirements of FAS 123R, *Share-Based Payment*, the Net decrease (increase) in operating working capital includes reductions of $96 and $94 for excess income tax benefits associated with stock options exercised during 2007 and 2006, respectively. These amounts are offset by Net purchases of treasury shares.

The 2007 Net purchases of other short-term investments consist of $799 in restricted cash associated with capital-investment projects at the company s Pascagoula, Mississippi refinery and Angola liquefied natural gas project that was invested in short-term marketable securities and reclassified from cash equivalents to a long-term deferred asset on the Consolidated Balance Sheet. In December 2007, the company issued a $650 tax exempt Mississippi Gulf

Opportunity Zone Bond as a source of funds for the Pascagoula Refinery project.

The Net purchases of treasury shares represents the cost of common shares acquired in the open market less the cost of shares issued for share-based compensation plans. Open-market purchases totaled $7,036, $5,033 and $3,029 in 2007, 2006 and 2005, respectively.

The major components of Capital expenditures and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, presented in Management s Discussion and Analysis, beginning on page FS-2, are presented in the following table:

	Year ended December 31		
	2007	2006	2005
Additions to properties, plant and equipment*	**$ 16,127**	$ 12,800	$ 8,154
Additions to investments	**881**	880	459
Current-year dry hole expenditures	**418**	400	198
Payments for other liabilities and assets, net	**(748)**	(267)	(110)
Capital expenditures	**16,678**	13,813	8,701
Expensed exploration expenditures	**816**	844	517
Assets acquired through capital lease obligations and other financing obligations	**196**	35	164
Capital and exploratory expenditures, excluding equity affiliates	**17,690**	14,692	9,382
Equity in affiliates expenditures	**2,336**	1,919	1,681
Capital and exploratory expenditures, including equity affiliates	**$ 20,026**	$ 16,611	$ 11,063

*Net of noncash additions of $3,560 in 2007, $440 in 2006 and $435 in 2005.

Note 4

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, other than natural gas liquids, excluding most of the regulated pipeline operations of Chevron. CUSA also holds Chevron s investment in the Chevron Phillips Chemical Company LLC (CPChem) joint venture which is accounted for using the equity method.

During 2007, 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 on the following page gives retroactive effect to the reorganizations as if they had occurred on January 1, 2005. However, the financial information on the following page may not reflect the financial position and operating results in the periods presented if the reorganization actually had occurred on that date.

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

Note 4 Summarized Financial Data Chevron U.S.A. Inc.
Continued

	Year ended December 31		
	2007	2006	2005
Sales and other operating revenues	**$ 153,574**	$ 145,774	$ 137,866
Total costs and other deductions	**147,510**	137,765	131,809
Net income	**5,203**	5,668	4,775

	At December 31	
	2007	2006
Current assets	**$ 32,803**	$ 26,066
Other assets	**27,401**	23,538
Current liabilities	**20,050**	16,917
Other liabilities	**11,447**	9,037
Net equity	**28,707**	23,650
Memo: Total debt	**$ 4,433**	$ 3,465

Note 5
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 presented in the following table:

	Year ended December 31		
	2007	2006	2005
Sales and other operating revenues	**$ 667**	$ 692	$ 640
Total costs and other deductions	**713**	602	509
Net income	**(39)**	119	113

At December 31

	2007	2006
Current assets	**$ 335**	$ 413
Other assets	**337**	345
Current liabilities	**107**	92
Other liabilities	**188**	250
Net equity	**377**	416

There were no restrictions on CTC s ability to pay dividends or make loans or advances at December 31, 2007.

Note 6

Stockholders Equity

Retained earnings at December 31, 2007 and 2006, included approximately $7,284 and $5,580, respectively, for the company s share of undistributed earnings of equity affiliates.

At December 31, 2007, about 120 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). In addition,

approximately 454,000 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 (Non-Employee Directors Plan).

Note 7

Financial and Derivative Instruments

For the financial and derivative instruments discussed below, no material change in market risk occurred relative to the information presented in 2006.

Commodity Derivative 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. The company also uses derivative commodity instruments for limited trading purposes.

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 marked-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.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as Accounts and notes receivable, Accounts payable, Long-term receivables net and Deferred credits and other noncurrent obligations. Ga and losses on the company s risk management activities are reported as either Sales and other operating revenues or Purchased crude oil and products, whereas trading gains and losses are reported as Other income.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

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Note 7 Financial and Derivative Instruments   Continued

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as Accounts and notes receivable or Accounts payable, with gains and losses reported as Other income.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company s fixed-rate debt are accounted for as fair value hedges.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as Accounts and notes receivable or Accounts payable.

Fair Value Fair values are derived from quoted market prices, other independent third-party quotes or, if not available, the present value of the expected cash flows. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end.

Long-term debt of $2,132 and $5,131 had estimated fair values of $2,325 and $5,621 at December 31, 2007 and 2006, respectively.

The company holds cash equivalents and marketable securities in U.S. and non-U.S. portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had carrying/fair values of $5,427 and $9,200 at December 31, 2007 and 2006, respectively. Of these balances, $4,695 and $8,247 at the respective year-ends were classified as cash equivalents that had average maturities under 90 days. The remainder, classified as marketable securities, had average maturities of approximately one year. At December 31, 2007, restricted cash with a carrying/fair value of $799 that is related to capital-investment projects at the company s Pascagoula, Mississippi refinery and Angola liquefied natural gas project was reclassified from cash equivalents to a long-term deferred asset on the Consolidated Balance Sheet. This restricted cash was invested in short-term marketable securities.

Fair values of other financial and derivative instruments at the end of 2007 and 2006 were not material.

Concentrations of Credit Risk The company s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, 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. This diversified investment policy limits the company s exposure both to credit risk and to concentrations of credit risk. Similar standards of diversity 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 consequence, 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 8

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. For this purpose, the investments are grouped as follows: upstream exploration and production; downstream refining, marketing and transportation; chemicals; and all other. The first three of these groupings represent the company s reportable segments and operating segments as defined in Financial Accounting Standards Board (FASB) Statement No. 131, *Disclosures About Segments of an Enterprise and Related Information* (FAS 131).

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 FAS 131). The CODM is the company s Executive Committee, a committee of senior officers that includes the Chief Executive Officer and that, in turn, reports to the Board of Directors of Chevron Corporation.

The operating segments represent components of the company as described in FAS 131 terms 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 to assess their performance; and (c) for which discrete financial information is available.

Segment managers for the reportable segments are accountable directly 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 Executive Committee also have individual management responsibilities and participate in other committees for purposes other than acting as the CODM.

All Other activities include the company s interest in Dynegy (through May 2007, when Chevron sold its interest), 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.

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

Note 8 Operating Segments and Geographic Data Continued

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. After-tax segment income by major operating area is presented in the following table:

	Year ended December 31		
	2007	2006	2005
Income by Major Operating Area			
Upstream			
United States	**$ 4,532**	$ 4,270	$ 4,168
International	**10,284**	8,872	7,556
Total Upstream	**14,816**	13,142	11,724
Downstream			
United States	**966**	1,938	980
International	**2,536**	2,035	1,786
Total Downstream	**3,502**	3,973	2,766
Chemicals			
United States	**253**	430	240
International	**143**	109	58
Total Chemicals	**396**	539	298
Total Segment Income	**18,714**	17,654	14,788
All Other			
Interest expense	**(107)**	(312)	(337)
Interest income	**385**	380	266
Other	**(304)**	(584)	(618)
Net Income	**$ 18,688**	$ 17,138	$ 14,099

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2007 and 2006 are as follows:

	At December 31 2007	2006
Upstream		
United States	**$ 23,535**	$ 20,727
International	**61,049**	51,844
Goodwill	**4,637**	4,623
Total Upstream	**89,221**	77,194
Downstream		
United States	**16,790**	13,482
International	**26,075**	22,892
Total Downstream	**42,865**	36,374
Chemicals		
United States	**2,484**	2,568
International	**870**	832
Total Chemicals	**3,354**	3,400
Total Segment Assets	**135,440**	116,968
All Other*		
United States	**6,847**	8,481
International	**6,499**	7,179
Total All Other	**13,346**	15,660
Total Assets United States	**49,656**	45,258
Total Assets International	**94,493**	82,747
Goodwill	**4,637**	4,623
Total Assets	**$ 148,786**	$ 132,628

* All Other assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company s investment in Dynegy prior to its disposition in 2007, mining operations, power generation businesses, 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 2007, 2006 and 2005 are presented in the following table. 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, kerosene, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Revenues for the chemicals segment are derived primarily from the manufacture and sale of additives for lubricants and fuel. All Other activities include revenues from mining operations of coal and other minerals, 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 2007.

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Note 8 Operating Segments and Geographic Data Continued

	Year ended December 31		
	2007	2006	2005
Upstream			
United States	**$ 18,736**	$ 18,061	$ 16,044
Intersegment	**11,625**	10,069	8,651
Total United States	**30,361**	28,130	24,695
International	**15,213**	14,560	10,190
Intersegment	**19,647**	17,139	13,652
Total International	**34,860**	31,699	23,842
Total Upstream	**65,221**	59,829	48,537
Downstream			
United States	**70,535**	69,367	73,721
Excise and similar taxes	**4,990**	4,829	4,521
Intersegment	**491**	533	535
Total United States	**76,016**	74,729	78,777
International	**97,178**	91,325	83,223
Excise and similar taxes	**5,042**	4,657	4,184
Intersegment	**38**	37	14
Total International	**102,258**	96,019	87,421
Total Downstream	**178,274**	170,748	166,198
Chemicals			
United States	**351**	372	343
Excise and similar taxes	**2**	2	
Intersegment	**235**	243	241
Total United States	**588**	617	584
International	**1,143**	959	760
Excise and similar taxes	**86**	63	14

Intersegment	**142**	160	131
Total International	**1,371**	1,182	905
Total Chemicals	**1,959**	1,799	1,489
All Other			
United States	**757**	653	597
Intersegment	**760**	584	514
Total United States	**1,517**	1,237	1,111
International	**58**	44	44
Intersegment	**31**	23	26
Total International	**89**	67	70
Total All Other	**1,606**	1,304	1,181
Segment Sales and Other Operating Revenues			
United States	**108,482**	104,713	105,167
International	**138,578**	128,967	112,238
Total Segment Sales and Other Operating Revenues	**247,060**	233,680	217,405
Elimination of intersegment sales	**(32,969)**	(28,788)	(23,764)
Total Sales and Other Operating Revenues*	**$ 214,091**	$ 204,892	$ 193,641

*Includes buy/sell contracts of $6,725 in 2006 and $23,822 in 2005. Substantially all of the amounts in each period relate to the downstream segment. Refer to Note 13, on page FS-42, for a discussion of the company s accounting for buy/sell contracts.

Segment Income Taxes Segment income tax expense for the years 2007, 2006 and 2005 are as follows:

	Year ended December 31		
	2007	2006	2005
Upstream			
United States	**$ 2,541**	$ 2,668	$ 2,330
International	**11,307**	10,987	8,440
Total Upstream	**13,848**	13,655	10,770
Downstream			
United States	**520**	1,162	575
International	**400**	586	576
Total Downstream	**920**	1,748	1,151
Chemicals			
United States	**6**	213	99

International	**36**	30	25
Total Chemicals	**42**	243	124
All Other	**(1,331)**	(808)	(947)
Total Income Tax Expense	**$ 13,479**	$ 14,838	$ 11,098

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 11, beginning on page FS-40. Information related to properties, plant and equipment by segment is contained in Note 12, on page FS-42.

Note 9

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. 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	
	2007	2006*
Upstream	**$ 482**	$ 461
Downstream	**$ 551**	$ 550
Chemical and all other	**171**	2
Total	**1,204**	1,013
Less: Accumulated amortization	**628**	548
Net capitalized leased assets	**$ 576**	$ 465

*2006 conformed to 2007 presentation.

Rental expenses incurred for operating leases during 2007, 2006 and 2005 were as follows:

	Year ended December 31		
	2007	2006	2005
Minimum rentals	**$ 2,419**	$ 2,326	$ 2,102
Contingent rentals	**6**	6	6
Total	**2,425**	2,332	2,108
Less: Sublease rental income	**30**	33	43
Net rental expense	**$ 2,395**	$ 2,299	$ 2,065

Notes to the Consolidated Financial Statements
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Note 9 Lease Commitments Continued

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, 2007, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a non-cancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2008	$ 513	$ 103
2009	478	106
2010	430	83
2011	347	85
2012	293	91
Thereafter	1,106	347
Total	$ 3,167	$ 815
Less: Amounts representing interest and executory costs		(315)
Net present values		500
Less: Capital lease obligations included in short-term debt		(94)
Long-term capital lease obligations		$ 406

Note 10

Restructuring and Reorganization Costs

In 2007, the company implemented a restructuring and reorganization program in its downstream operations. Approximately 1,000 employees were eligible for severance payments. Most of the associated positions are located outside the United States. The majority of the terminations are expected to occur in 2008 and the program is expected to be complete by the end of 2009.

Shown in the table below is the activity for the company s liability related to the downstream reorganization. The associated charges against income were categorized as Operating expenses or Selling, general and administrative expenses on the Consolidated Statement of Income.

Amounts before tax	**2007**

Balance at January 1	$
Additions	**85**
Payments	
Balance at December 31	**$ 85**

Note 11

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 table below. 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		
	2007	2006	**2007**	2006	2005
Upstream					
Tengizchevroil	**$ 6,321**	$ 5,507	**$ 2,135**	$ 1,817	$ 1,514
Hamaca	**1,168**	928	**327**	319	390
Petroboscan	**762**	712	**185**	31	
Angola LNG Limited	**574**		**21**		
Other	**765**	682	**204**	123	139
Total Upstream	**9,590**	7,829	**2,872**	2,290	2,043
Downstream					
GS Caltex Corporation	**2,276**	2,176	**217**	316	320
Caspian Pipeline Consortium	**951**	990	**102**	117	101
Star Petroleum Refining Company Ltd.	**944**	787	**157**	116	81
Escravos Gas-to-Liquids	**628**	432	**103**	146	95
Caltex Australia Ltd.	**580**	559	**129**	186	214
Colonial Pipeline Company	**546**	555	**39**	34	13
Other	**1,501**	1,407	**215**	212	178
Total Downstream	**7,426**	6,906	**962**	1,127	1,002
Chemicals					
Chevron Phillips Chemical Company LLC	**2,024**	2,044	**380**	697	449
Other	**24**	22	**6**	5	3
Total Chemicals	**2,048**	2,066	**386**	702	452
All Other					
Dynegy Inc.		254	**8**	68	189
Other	**449**	586	**(84)**	68	45
Total equity method	**$ 19,513**	$ 17,641	**$ 4,144**	$ 4,255	$ 3,731

Other at or below cost	**964**	911			
Total investments and advances	**$ 20,477**	$ 18,552			
Total United States	**$ 3,889**	$ 4,191	**$ 478**	$ 955	$ 833
Total International	**$ 16,588**	$ 14,361	**$ 3,666**	$ 3,300	$ 2,898

Descriptions of major 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, 2007, the company s carrying value of its investment in TCO was about $210 higher than the amount of underlying equity in TCO net assets.

Hamaca Chevron s 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela s Orinoco Belt was converted to a 30 percent share-holding in a joint stock company in January 2008, with a 25-year contract term.

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Note 11 Investments and Advances Continued

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, 2007, the company s carrying value of its investment in Petroboscan was approximately $310 higher than the amount of underlying equity in Petroboscan net assets.

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

GS Caltex Corporation Chevron owns 50 percent of GS Caltex, a joint venture with GS Holdings. The joint venture, originally formed in 1967 between the LG Group and Caltex, imports, refines and markets petroleum products and petrochemicals predominantly in South Korea.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC), which provides the critical export route for crude oil from both TCO and Karachaganak. At December 31, 2007, the company s carrying value of its investment in CPC was about $50 higher than the amount of underlying equity in CPC net assets.

Star Petroleum Refining Company Ltd. Chevron has a 64 percent equity ownership interest in Star Petroleum Refining Company Limited (SPRC), which owns the Star Refinery in Thailand. The Petroleum Authority of Thailand owns the remaining 36 percent of SPRC.

Escravos Gas-to-Liquids Chevron Nigeria Limited (CNL) has a 75 percent interest in Escravos Gas-to-Liquids (EGTL) with the other 25 percent of the joint venture owned by Nigeria National Petroleum Company. Sasol Ltd provides 50 percent of the venture capital required by CNL as risk-based financing (returns are based on project performance). This venture was formed to convert natural gas produced from Chevron s Nigerian operations into liquid products for sale in international markets. At December 31, 2007, the company s carrying value of its investment in EGTL was about $25 lower than the amount of underlying equity in EGTL net assets.

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2007, the fair value of Chevron s share of CAL common stock was approximately $2,294. The aggregate carrying value of the company s investment in CAL was approximately $50 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest in the Colonial Pipeline Company. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market. At December 31, 2007, the company s carrying value of its investment in Colonial Pipeline was approximately $580 higher than the amount of underlying equity in Colonial Pipeline net assets.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC (CPChem), with the other half owned by ConocoPhillips Corporation. At December 31, 2007, the company s carrying value of its investment in CPChem was approximately $60 lower than the amount of underlying equity in CPChem net assets.

Dynegy Inc. In May 2007, Chevron sold its 19 percent common stock investment in Dynegy Inc., a provider of electricity to markets and customers throughout the United States, for approximately $940, resulting in a gain of $680.

Other Information Sales and other operating revenues on the Consolidated Statement of Income includes $11,555, $9,582 and $8,824 with affiliated companies for 2007, 2006 and 2005, respectively. Purchased crude oil and products includes $5,464, $4,222 and $3,219 with affiliated companies for 2007, 2006 and 2005, respectively.

Accounts and notes receivable on the Consolidated Balance Sheet includes $1,722 and $1,297 due from affiliated companies at December 31, 2007 and 2006, respectively. Accounts payable includes $374 and $262 due to affiliated companies at December 31, 2007 and 2006, respectively.

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Millions of dollars, except per-share amounts

Note 11 Investments and Advances   Continued

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 $4,124 at December 31, 2007.

	Affiliates			Chevron Share		
Year ended December 31	**2007**	2006	2005	**2007**	2006	2005
Total revenues	**$ 94,864**	$ 73,746	$ 64,642	**$ 46,579**	$ 35,695	$ 31,252
Income before income tax expense	**12,510**	10,973	7,883	**5,836**	5,295	4,165
Net income	**9,743**	7,905	6,645	**4,550**	4,072	3,534
At December 31						
Current assets	**$ 26,360**	$ 19,769	$ 19,903	**$ 11,914**	$ 8,944	$ 8,537
Noncurrent assets	**48,440**	49,896	46,925	**19,045**	18,575	17,747
Current liabilities	**19,033**	15,254	13,427	**9,009**	6,818	6,034
Noncurrent liabilities	**22,757**	24,059	26,579	**3,745**	3,902	4,906
Net equity	**$ 33,010**	$ 30,352	$ 26,822	**$ 18,205**	$ 16,799	$ 15,344

Note 12

Properties, Plant and Equipment

	Gross Investment at Cost			At December 31 Net Investment			Additions at Cost[1]			Year ended December 3 Depreciation Expense		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	200
pstream												
nited States	**$ 50,991**	$ 46,191	$ 43,390	**$ 19,850**	$ 16,706	$ 15,327	**$ 5,725**	$ 3,739	$ 2,160	**$ 2,700**	$ 2,374	$ 1,869
ternational	**71,408**	61,281	54,497	**43,431**	37,730	34,311	**10,512**	7,290	4,897	**4,605**	3,888	2,804
otal pstream	**122,399**	107,472	97,887	**63,281**	54,436	49,638	**16,237**	11,029	7,057	**7,305**	6,262	4,673
ownstream												
nited States	**15,807**	14,553	13,832	**7,685**	6,741	6,169	**1,514**	1,109	793	**509**	474	461
ternational	**10,471**	11,036	11,235	**4,690**	5,233	5,529	**519**	532	453	**633**	551	550

otal ownstream	**26,278**	25,589	25,067	**12,375**	11,974	11,698	**2,033**	1,641	1,246	**1,142**	1,025	1,011
hemicals												
nited States	**678**	645	624	**308**	289	282	**40**	25	12	**19**	19	19
nternational	**815**	771	721	**453**	431	402	**53**	54	43	**26**	24	23
otal hemicals	**1,493**	1,416	1,345	**761**	720	684	**93**	79	55	**45**	43	42
ll Other[3]												
nited States	**3,873**	3,243	3,127	**2,179**	1,709	1,655	**680**	270	199	**215**	171	186
nternational	**41**	27	20	**14**	19	15	**5**	8	4	**1**	5	1
otal All ther	**3,914**	3,270	3,147	**2,193**	1,728	1,670	**685**	278	203	**216**	176	187
otal United tates	**71,349**	64,632	60,973	**30,022**	25,445	23,433	**7,959**	5,143	3,164	**3,443**	3,038	2,535
otal nternational	**82,735**	73,115	66,473	**48,588**	43,413	40,257	**11,089**	7,884	5,397	**5,265**	4,468	3,378
otal	**$ 154,084**	$ 137,747	$ 127,446	**$ 78,610**	$ 68,858	$ 63,690	**$ 19,048**	$ 13,027	$ 8,561	**$ 8,708**	$ 7,506	$ 5,913

[1] Net of dry hole expense related to prior years expenditures of $89, $120 and $28 in 2007, 2006 and 2005, respectively.

[2] Depreciation expense includes accretion expense of $399, $275 and $187 in 2007, 2006 and 2005, respectively.

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

Note 13

Accounting for Buy/Sell Contracts

The company adopted the accounting prescribed by Emerging Issues Task Force (EITF) Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (Issue 04-13) on a prospective basis from April 1, 2006. Issue 04-13 requires that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, be combined and considered as a single arrangement for purposes of applying the provisions of Accounting Principles Board Opinion No. 29, *Accounting for Nonmonetary Transactions,* when the transactions are entered into in contemplation of one another. In prior

periods, the company accounted for buy/sell transactions in the Consolidated Statement of Income as a monetary transaction purchases were reported as Purchased crude oil and products ; sales were reported as Sales and other operating revenues.

With the company s adoption of Issue 04-13, buy/sell transactions beginning in the second quarter 2006 are netted against each other on the Consolidated Statement of Income, with no effect on net income. Amounts associated with buy/sell transactions in periods prior to the second quarter 2006 are shown as a footnote to the Consolidated Statement of Income on page FS-27.

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Note 14

Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. The company is a party to 88 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepages of MTBE into groundwater. Chevron has agreed in principle to a tentative settlement of 60 pending lawsuits and claims. The terms of this agreement, which must be approved by a number of parties, including the court, are confidential and not material to the company s results of operations, liquidity or financial position.

Resolution of remaining 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 tentative settlement of the referenced 60 lawsuits did not set any precedents related to standards of liability to be used to judge the merits of the claims, corrective measures required or monetary damages to be assessed for the remaining lawsuits and claims or future lawsuits and claims. As a result, the company s ultimate exposure related to pending lawsuits and claims is not currently 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.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal s undisclosed and pending patents. Eleven lawsuits were consolidated in U.S. District Court for the Central District of California, where a class action has been certified, and three were consolidated in a state court action. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys fees, and interest on behalf of an alleged class of consumers who purchased summertime RFG in California from January 1995 through August 2005. The parties have reached a tentative agreement to resolve all of the above matters in an amount that is not material to the company s results of operations, liquidity or

financial position. The terms of this agreement are confidential, and subject to further negotiation and approval, including by the courts.

Note 15

Taxes

Income Taxes

	Year ended December 31		
	2007	2006	2005
Taxes on income			
U.S. Federal			
Current	**$ 1,446**	$ 2,828	$ 1,459
Deferred	**225**	200	567
State and local	**338**	581	409

Total United States	**2,009**	3,609	2,435
International			
Current	**11,416**	11,030	7,837
Deferred	**54**	199	826
Total International	**11,470**	11,229	8,663
Total taxes on income	**$ 13,479**	$ 14,838	$ 11,098

In 2007, before-tax income for U.S. operations, including related corporate and other charges, was $7,794, compared with before-tax income of $9,131 and $6,733 in 2006 and 2005, respectively. For international operations, before-tax income was $24,373, $22,845 and $18,464 in 2007, 2006 and 2005, respectively. U.S. federal income tax expense was reduced by $132, $116 and $289 in 2007, 2006 and 2005, 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 table below:

	Year ended December 31		
	2007	2006	2005
U.S. statutory federal income tax rate	**35.0%**	35.0%	35.0%
Effect of income taxes from international operations at rates different from the U.S. statutory rate	**8.3**	10.3	9.2
State and local taxes on income, net of U.S. federal income tax benefit	**0.8**	1.0	1.0
Prior-year tax adjustments	**0.3**	0.9	0.1
Tax credits	**(0.4)**	(0.4)	(1.1)
Effects of enacted changes in tax laws	**(0.3)**	0.3	
Other	**(1.8)**	(0.7)	(0.1)
Effective tax rate	**41.9%**	46.4%	44.1%

The company s effective tax rate decreased by 4.5 percent in 2007 from the prior year. The 2 percent decrease pertaining to the Effect of income taxes from international

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

Note 15 Taxes   Continued

operations ...   was primarily due to the impact of asset sales and to lower effective tax rates in certain non-U.S. operations. The 1 percent decrease in   Other   primarily relates to the effects of asset sales in 2007.

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	
	2007	2006
Deferred tax liabilities		
Properties, plant and equipment	**$ 17,310**	$ 16,054
Investments and other	**1,837**	2,137
Total deferred tax liabilities	**19,147**	18,191
Deferred tax assets		
Abandonment/environmental reserves	**(3,587)**	(2,925)
Employee benefits	**(2,148)**	(2,707)
Tax loss carryforwards	**(1,603)**	(1,509)
Capital losses		(246)
Deferred credits	**(1,689)**	(1,670)
Foreign tax credits	**(3,138)**	(1,916)
Inventory	**(608)**	(378)
Other accrued liabilities	**(477)**	(375)
Miscellaneous	**(1,528)**	(1,144)
Total deferred tax assets	**(14,778)**	(12,870)
Deferred tax assets valuation allowance	**5,949**	4,391
Total deferred taxes, net	**$ 10,318**	$ 9,712

In 2007, deferred tax liabilities increased by approximately $1,000 from the amount reported in 2006. The increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets increased by approximately $1,900 in 2007. The increase related primarily to additional foreign tax credits arising from earnings in high-tax-rate international jurisdictions. This increase was substantially offset by valuation allowances.

The overall valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences for which no benefit is expected to be realized. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2008 through 2029. Foreign tax credit carryforwards of $3,138 will expire between 2008 and 2017.

At December 31, 2007 and 2006, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2007	2006
Prepaid expenses and other current assets	**$ (1,234)**	$ (1,167)
Deferred charges and other assets	**(812)**	(844)
Federal and other taxes on income	**194**	76
Noncurrent deferred income taxes	**12,170**	11,647
Total deferred income taxes, net	**$ 10,318**	$ 9,712

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 $20,557 at December 31, 2007. 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 2007, 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 Effective January 1, 2007, the company implemented Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109* (FIN 48), which clarifies the accounting for income tax benefits that are uncertain in nature. This interpretation was intended by the standard-setters to address the diversity in practice that existed in this area of accounting for income taxes.

Under FIN 48, 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 FIN 48 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 accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, recognition of interest and penalties, and accounting for the cumulative-effect adjustment at the date of adoption. Upon adoption of FIN 48 on January 1, 2007, the company recorded a cumulative-effect adjustment that reduced retained earnings by $35.

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Note 15 Taxes Continued

The following table indicates the changes to the company s unrecognized tax benefits for the year ended December 31, 2007. The term unrecognized tax benefits in FIN 48 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 in accordance with the guidelines of FIN 48. Interest and penalties are not included.

Balance at January 1, 2007 (date of FIN 48 adoption)	$ 2,296
Foreign currency effects	19
Additions based on tax positions taken in 2007	418
Additions for tax positions taken in prior years	120
Reductions for tax positions taken in prior years	(225)
Settlements with taxing authorities in 2007	(255)
Reductions due to tax positions previously expected to be taken but subsequently not taken on 2006 tax returns	(174)
Balance at December 31, 2007	$ 2,199

The only individually significant change for 2007 was a reduction in an unrecognized tax benefit for a position previously expected to be taken but subsequently not taken on a 2006 tax return. Although unrecognized tax benefits for individual tax positions may increase or decrease during 2008, the company believes that no change will be individually significant during 2008. Approximately 80 percent of the $2,199 of unrecognized tax benefits at December 31, 2007, would have an impact on the overall tax rate if subsequently recognized.

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, 2007. In this regard, the company received a final U.S. federal income tax audit report for years 2002 and 2003 in March 2007. In early 2008, the company s 2004 and 2005 tax returns were under examination by the Internal Revenue Service. For other major tax jurisdictions, the latest years for which income tax examinations had been finalized were as follows: Nigeria 1994, Angola 2001 and Saudi Arabia 2003.

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, 2007, accruals of $198 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet. For the year 2007, income tax expense associated with interest and penalties was not material.

Taxes Other Than on Income

	Year ended December 31		
	2007	2006	2005
United States			
Excise and similar taxes on products and merchandise	**$ 4,992**	$ 4,831	$ 4,521

Import duties and other levies	**12**	32	8
Property and other miscellaneous taxes	**491**	475	392
Payroll taxes	**185**	155	149
Taxes on production	**288**	360	323
Total United States	**5,968**	5,853	5,393
International			
Excise and similar taxes on products and merchandise	**5,129**	4,720	4,198
Import duties and other levies	**10,404**	9,618	10,466
Property and other miscellaneous taxes	**528**	491	535
Payroll taxes	**89**	75	52
Taxes on production	**148**	126	138
Total International	**16,298**	15,030	15,389
Total taxes other than on income	**$ 22,266**	$ 20,883	$ 20,782

Note 16
Short-Term Debt

	At December 31	
	2007	2006
Commercial paper*	**$ 3,030**	$ 3,472
Notes payable to banks and others with originating terms of one year or less	**219**	122
Current maturities of long-term debt	**850**	2,176
Current maturities of long-term capital leases	**73**	57
Redeemable long-term obligations		
Long-term debt	**1,351**	487
Capital leases	**21**	295
Subtotal	**5,544**	6,609
Reclassified to long-term debt	**(4,382)**	(4,450)
Total short-term debt	**$ 1,162**	$ 2,159

*Weighted-average interest rates at December 31, 2007 and 2006, were 4.35 percent and 5.25 percent, respectively.

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

The company periodically enters into interest rate swaps on a portion of its short-term debt. See Note 7, beginning on page FS-36, for information concerning the company s debt-related derivative activities.

At December 31, 2007, the company had $4,950 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company s commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based

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

Note 16 Short-Term Debt Continued

on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2007 or at year-end.

At December 31, 2007 and 2006, the company classified $4,382 and $4,450, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2008, as the company has both the intent and the ability to refinance this debt on a long-term basis.

Note 17

Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2007, was $5,664. The company s long-term debt outstanding at year-end 2007 and 2006 was as follows:

	At December 31	
	2007	2006
3.375% notes due 2008	**$ 749**	$ 738
5.5% notes due 2009	**405**	401
7.327% amortizing notes due 2014[1]	**213**	213
8.625% debentures due 2032	**161**	199
8.625% debentures due 2031	**108**	199
7.5% debentures due 2043	**85**	198
8% debentures due 2032	**81**	148
9.75% debentures due 2020	**57**	250
8.875% debentures due 2021	**46**	150
8.625% debentures due 2010	**30**	150
3.85% notes due 2008	**30**	
3.5% notes due 2007		1,996
7.09% notes due 2007		144
Medium-term notes, maturing from 2021 to 2038 (6.2%)[2]	**64**	210
Fixed interest rate notes, maturing from 2008 to 2011 (8.2%)[2]	**27**	46
Other foreign currency obligations (0.5%)[2]	**17**	23
Other long-term debt (7.4%)[2]	**59**	66
Total including debt due within one year	**2,132**	5,131
Debt due within one year	**(850)**	(2,176)
Reclassified from short-term debt	**4,382**	4,450
Total long-term debt	**$ 5,664**	$ 7,405

[1] Guarantee of ESOP debt.

[2] Weighted-average interest rate at December 31, 2007.

Long-term debt of $2,132 matures as follows: 2008 $850; 2009 $431; 2010 $65; 2011 $48; 2012 $33; and after 2012 $705.

In 2007, $2,000 of Chevron Canada Funding Company bonds matured. The company also redeemed early $874 of Texaco Capital Inc. bonds, at an after-tax loss of approximately $175. In 2006, $510 in bonds were retired at maturity and $1,700 of Unocal debt was redeemed early at a $92 before-tax gain.

Note 18

New Accounting Standards

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which became effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 does not require any new fair value measurements but applies to assets and liabilities that are required to be recorded at fair value under other accounting standards. The implementation of FAS 157 did not have a material effect on the company s results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Its Related Interpretive Accounting Pronouncements That Address Leasing Transactions (FSP 157-1) In February 2008, the FASB issued FSP 157-1, which became effective for the company on January 1, 2008. This FSP excludes FASB Statement No. 13, Accounting for Leases, and its related interpretive accounting pronouncements from the provisions of FAS 157. Implementation of this standard did not have a material effect on the company s results of operations or consolidated financial position.

FASB Staff Position FAS No. 157-2, Effective Date of FASB Statement No. 157 (FSP 157-2) In February 2008, the FASB issued FSP 157-2, which delays the company s January 1, 2008 effective date of FAS 157 for all nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until January 1, 2009. Implementation of this standard did not have a material effect on the company s results of operations or consolidated financial position.

FASB Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115 (FAS 159) In February 2007, the FASB issued FAS 159, which became effective for the company on January 1, 2008. This standard permits companies to choose to measure many financial instruments and certain other items at fair value and report unrealized gains and losses in earnings. Such accounting is optional and is generally to be applied instrument by instrument. The implementation of FAS 159 did not have a material effect on the company s results of operations or consolidated financial position.

FASB Statement No. 141 (revised 2007), Business Combinations (FAS 141-R) In December 2007, the FASB issued FAS 141-R, which will become effective for business combination transactions having an acquisition date on or after January 1, 2009. This standard requires the acquiring entity in a business combination to

Note 18 New Accounting Standards   Continued

recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date to be measured at their respective fair values. The Statement requires acquisition-related costs, as well as restructuring costs the acquirer expects to incur for which it is not obligated at acquisition date, to be recorded against income rather than included in purchase-price determination. It also requires recognition of contingent arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in income.
FASB Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (FAS 160)   The FASB issued FAS 160 in December 2007, which will become effective for the company January 1, 2009, with retroactive adoption of the Statement s presentation and disclosure requirements for existing minority interests. This standard will require ownership interests in subsidiaries held by parties other than the parent to be presented within the equity section of the consolidated statement of financial position but separate from the parent s equity. It will also require the amount of consolidated net income attributable to the parent and the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement. Certain changes in a parent s ownership interest are to be accounted for as equity transactions and when a subsidiary is deconsolidated, any noncontrolling equity investment in the former subsidiary is to be initially measured at fair value. The company does not anticipate the implementation of FAS 160 will significantly change the presentation of its consolidated income statement or consolidated balance sheet.

Note 19

Accounting for Suspended Exploratory Wells
The company accounts for the cost of exploratory wells in accordance with FASB Statement No. 19, *Financial and Reporting by Oil and Gas Producing Companies* (FAS 19)*,* as amended by FASB Staff Position (FSP) FAS 19-1, *Accounting for Suspended Well Costs*, which provides 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 enterprise 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. FAS 19 provides a number of indicators that can assist an entity to demonstrate 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, 2007. No capitalized exploratory well costs were charged to expense upon the 2005 adoption of FSP FAS 19-1.

	2007	2006	2005
Beginning balance at January 1	**$ 1,239**	$ 1,109	$ 671
Additions associated with the acquisition of Unocal			317
Additions to capitalized exploratory well costs pending the determination of proved reserves	**486**	446	290

Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(23)**	(171)	(140)
Capitalized exploratory well costs charged to expense	**(42)**	(121)	(6)
Other reductions*		(24)	(23)
Ending balance at December 31	**$ 1,660**	$ 1,239	$ 1,109

*Represent property sales and exchanges.

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. The aging of the former Unocal wells is based on the date the drilling was completed, rather than the date of Chevron s acquisition of Unocal in 2005.

	At December 31		
	2007	2006	2005
Exploratory well costs capitalized for a period of one year or less	**$ 449**	$ 332	$ 259
Exploratory well costs capitalized for a period greater than one year	**1,211**	907	850
Balance at December 31	**$ 1,660**	$ 1,239	$ 1,109
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**54**	44	40

*Certain projects have multiple wells or fields or both.

Of the $1,211 of exploratory well costs capitalized for more than one year at December 31, 2007, $750 (32 projects) is related to projects that had drilling activities under way or firmly planned for the near future. An additional $8 (three projects) is related to projects that had drilling activity during 2007. The $453 balance related to 19 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the $453 referenced above had the following activities associated with assessing the reserves and the

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

Note 19 Accounting For Suspended Exploratory Wells
Continued

projects economic viability: (a) $99 (one project) combined two projects into a single development project and submitted plans to government in 2007; (b) $74 (three projects) continued unitization efforts on adjacent discoveries that span international boundaries; (c) $74 (one project) finalizing field development evaluation; (d) $74 (one project) field rework continues to accommodate larger design capacity and finalize sales agreements; (e) $42 (one project) finalizing development concept; (f) $90 miscellaneous activities for 12 projects with smaller amounts suspended. While progress was being made on all 54 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 $1,211 of suspended well costs capitalized for a period greater than one year as of December 31, 2007, represents 127 exploratory wells in 54 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
1994 1996	$ 27	3
1997 2001	128	32
2002 2006	1,056	92
Total	$ 1,211	127

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
1999	$ 8	1
2003 2007	1,203	53
Total	$ 1,211	54

Note 20
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 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 provisions of the Pension Protection Act of 2006 (PPA) became effective for the company in 2008. These provisions change, among other things, the methodology for determining the interest rate to be used in calculating lump-sum benefits. This change in methodology increased the lump-sum interest rate and lowered the company s pension benefit obligations by about $300 at December 31, 2007. The effect of the interest rate change on pension plan contributions during 2008 is expected to be *de minimis*, as the company s funded pension plans are considered well-funded under PPA provisions.

The company also sponsors other postretirement 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 per year. Certain life insurance benefits are paid by the company.

Effective December 31, 2006, the company implemented the recognition and measurement provisions of Financial Accounting Standards Board Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)*(FAS 158), which requires the recognition of the overfunded or underfunded status of each of its defined benefit pension and other postretirement benefit plans as an asset or liability, with the offset to Accumulated other comprehensive loss.

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Note 20 Employee Benefit Plans Continued

The company uses a measurement date of December 31 to value its benefit plan assets and obligations. The funded status of the company s pension and other postretirement benefit plans for 2007 and 2006 is as follows:

	Pension Benefits				Other Benefits	
	2007		2006			
	U.S.	Int l.	U.S.	Int l.	**2007**	2006
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 8,792**	**$ 4,207**	$ 8,594	$ 3,611	**$ 3,257**	$ 3,252
Service cost	**260**	**125**	234	98	**49**	35
Interest cost	**483**	**255**	468	214	**184**	181
Plan participants contributions		**7**		7	**122**	134
Plan amendments	**(301)**	**97**	14	37		107
Curtailments		**(12)**				
Actuarial (gain) loss	**(131)**	**(40)**	297	97	**(413)**	(102)
Foreign currency exchange rate changes		**219**		355	**12**	(5)
Benefits paid	**(708)**	**(225)**	(815)	(212)	**(272)**	(345)
Benefit obligation at December 31	**8,395**	**4,633**	8,792	4,207	**2,939**	3,257
Change in Plan Assets						
Fair value of plan assets at January 1	**7,941**	**3,456**	7,463	2,890		
Actual return on plan assets	**607**	**232**	1,069	225		
Foreign currency exchange rate changes		**183**		321		
Employer contributions	**78**	**239**	224	225	**150**	211
Plan participants contributions		**7**		7	**122**	134
Benefits paid	**(708)**	**(225)**	(815)	(212)	**(272)**	(345)
Fair value of plan assets at December 31	**7,918**	**3,892**	7,941	3,456		
Funded Status at December 31	**$ (477)**	**$ (741)**	$ (851)	$ (751)	**$ (2,939)**	$ (3,257)

Amounts recognized on the Consolidated Balance Sheet for the company s pension and other postretirement benefit plans at December 31, 2007 and 2006, include:

Pension Benefits

	2007		2006		Other Benefits	
	U.S.	Int l.	U.S.	Int l.	**2007**	2006
Deferred charges and other assets	**$ 181**	**$ 279**	$ 18	$ 96	**$**	$
Accrued liabilities	**(68)**	**(55)**	(53)	(47)	**(207)**	(223)
Reserves for employee benefit plans	**(590)**	**(965)**	(816)	(800)	**(2,732)**	(3,034)
Net amount recognized at December 31	**$ (477)**	**$ (741)**	$ (851)	$ (751)	**$ (2,939)**	$ (3,257)

Amounts recognized on a before-tax basis in Accumulated other comprehensive loss for the company s pension and other postretirement plans were $2,990 and $4,065 at the end of 2007 and 2006. These amounts consisted of:

	Pension Benefits					
	2007		2006		Other Benefits	
	U.S.	Int l.	U.S.	Int l.	**2007**	2006
Net actuarial loss	**$ 1,539**	**$ 1,237**	$ 1,892	$ 1,288	**$ 490**	$ 972
Prior-service costs (credit)	**(75)**	**203**	272	126	**(404)**	(485)
Total recognized at December 31	**$ 1,464**	**$ 1,440**	$ 2,164	$ 1,414	**$ 86**	$ 487

The accumulated benefit obligations for all U.S. and international pension plans were $7,712 and $4,000, respectively, at December 31, 2007, and $7,987 and $3,669, respectively, at December 31, 2006.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2007 and 2006, was:

	Pension Benefits			
	2007		2006	
	U.S.	Int l.	U.S.	Int l.
Projected benefit obligations	**$ 678**	**$ 1,089**	$ 848	$ 849
Accumulated benefit obligations	**638**	**926**	806	741
Fair value of plan assets	**20**	**271**	12	172

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Note 20 Employee Benefit Plans Continued

The components of net periodic benefit cost for 2007, 2006 and 2005 and amounts recognized in other comprehensive income for 2007 are shown in the table below. For 2007, changes in pension plan assets and benefit obligations were recognized as changes in other comprehensive income.

	Pension Benefits						Other Benefits		
	2007		2006		2005				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2007**	2006	2005
Net Periodic Benefit Cost									
Service cost	**$ 260**	**$ 125**	$ 234	$ 98	$ 208	$ 84	**$ 49**	$ 35	$ 30
Interest cost	**483**	**255**	468	214	395	199	**184**	181	164
Expected return on plan assets	**(578)**	**(266)**	(550)	(227)	(449)	(208)			
Amortization of transitional assets				1		2			
Amortization of prior-service costs (credits)	**46**	**17**	46	14	45	16	**(81)**	(86)	(91)
Recognized actuarial losses	**128**	**82**	149	69	177	51	**81**	97	93
Settlement losses	**65**		70		86				
Curtailment losses		**3**							
Net periodic benefit cost	**404**	**216**	417	169	462	144	**233**	227	196
Changes Recognized in Other Comprehensive Income									
Net actuarial (gain) loss during period	**(160)**	**31**					**(401)**		
Amortization of actuarial (loss)	**(193)**	**(82)**					**(81)**		
Prior service (credit) cost during period	**(301)**	**97**							
Amortization of prior-service (costs) credits	**(46)**	**(20)**					**81**		

Total changes recognized in other comprehensive income	**(700)**	**26**					**(401)**		
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ (296)**	**$ 242**	$ 417	$ 169	$ 462	$ 144	**$ (168)**	$ 227	$ 196

Net actuarial losses recorded in Accumulated other comprehensive loss at December 31, 2007, for the company s U.S. pension, international pension and other postretirement benefit plans are being amortized on a straight-line basis over approximately 10, 13 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 2008, the company estimates actuarial losses of $59, $80 and $39 will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and other postretirement benefit plans, respectively. In addition, the company estimates an additional $78 will be recognized from Accumulated other comprehensive loss during 2008 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, 2007, was approximately nine and 11 years for U.S. and international pension plans, respectively, and six years for other postretirement benefit plans. During 2008, the company estimates prior service (credits) costs of $(7), $25 and $(81) will be amortized from Accumulated other comprehensive loss for U.S. pension, international pension and other postretirement benefit plans, respectively.

Note 20 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						Other Benefits		
	2007		2006		2005				
	U.S.	Int l.	U.S.	Int l.	U.S.	Int l.	**2007**	2006	2005
Assumptions used to determine benefit obligations									
Discount rate	**6.3%**	**6.7%**	5.8%	6.0%	5.5%	5.9%	**6.3%**	5.8%	5.6%
Rate of compensation increase	**4.5%**	**6.4%**	4.5%	6.1%	4.0%	5.1%	**4.5%**	4.5%	4.0%
Assumptions used to determine net periodic benefit cost									
Discount rate[1,2]	**5.8%**	**6.0%**	5.8%	5.9%	5.5%	6.4%	**5.8%**	5.9%	5.8%
Expected return on plan assets[1]	**7.8%**	**7.5%**	7.8%	7.4%	7.8%	7.9%	**N/A**	N/A	N/A
Rate of compensation increase[1]	**4.5%**	**6.1%**	4.2%	5.1%	4.0%	5.0%	**4.5%**	4.2%	4.0%

1 The 2005 discount rate, expected return on plan assets and rate of compensation increase reflect the remeasurement of the acquired Unocal benefit plans at July 31, 2005.

2 The 2006 U.S. discount rate reflects remeasurement on July 1, 2006, due to plan combinations and changes, primarily several Unocal plans into related Chevron plans.

Expected Return on Plan Assets The company s estimated long-term rate of return on pension assets is 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 67 percent of the company s pension plan assets. At December 31, 2007, 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-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of the measurement date 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, 2007, the company selected a 6.3 percent discount rate for the major U.S. pension and postretirement plans. 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 2007. The discount rates at the end of 2006 and 2005 were 5.8 percent and 5.5 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2007, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 8 percent in 2008 and gradually decline to 5 percent for 2014 and beyond. For this measurement at December 31, 2006, the assumed health care cost-trend rates started with 9 percent in 2007 and gradually declined to 5 percent for 2011 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	$ 9	$ (8)
Effect on postretirement benefit obligation	$ 86	$ (75)

Plan Assets and Investment Strategy The company s pension plan weighted-average asset allocations at December 31 by asset category are as follows:

	U.S.		International	
Asset Category	**2007**	2006	**2007**	2006
Equities	**64%**	68%	**56%**	62%
Fixed Income	**23%**	21%	**43%**	37%
Real Estate	**12%**	10%	**1%**	1%
Other	**1%**	1%		
Total	**100%**	100%	**100%**	100%

The pension plans invest primarily in asset categories with sufficient size, liquidity and cost efficiency to permit investments of reasonable size. The pension plans invest in asset categories that provide diversification benefits and are easily measured. To assess

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Note 20 Employee Benefit Plans   Continued

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 approved the following percentage asset-allocation ranges: Equities 40 70, Fixed Income/Cash 20 60, Real Estate 0 15 and Other 0 5. The significant international pension plans also have established maximum and minimum asset allocation ranges that vary by each plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset category risk.

Equities include investments in the company s common stock in the amount of $36 and $17 at December 31, 2007 and 2006, respectively. The   Other   asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments   In 2007, the company contributed $78 and $239 to its U.S. and international pension plans, respectively. In 2008, the company expects contributions to be approximately $300 and $200 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon plan-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 $207 in 2008, as compared with $150 paid in 2007.

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

	Pension Benefits		Other
	U.S.	Int l.	Benefits
2008	$ 832	$ 238	$ 207
2009	$ 841	$ 272	$ 213
2010	$ 849	$ 282	$ 219
2011	$ 856	$ 279	$ 225
2012	$ 863	$ 296	$ 228
2013 2017	$ 4,338	$ 1,819	$ 1,195

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 follows. Total company matching contributions to employee accounts within the ESIP were $206, $169 and $145 in 2007, 2006 and 2005, respectively. This cost was reduced by the value of shares released from the LESOP totaling

$33, $6 and $4 in 2007, 2006 and 2005, respectively. The remaining amounts, totaling $173, $163 and $141 in 2007, 2006 and 2005, 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 American Institute of Certified Public Accountants (AICPA) Statement of Position 93-6, *Employers Accounting for Employee Stock Ownership Plans*, the company has elected to continue its practices, which are based on AICPA Statement of Position 76-3, *Accounting Practices for Certain Employee Stock Ownership Plans*, and subsequent consensus of the EITF of the FASB. 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 Stockholders 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) expenses recorded for the LESOP were $(1), $(1) and $94 in 2007, 2006 and 2005, respectively, including $16, $17 and $18 of interest expense related to LESOP debt and a (credit) charge to compensation expense of $(17), $(18) and $76.

Of the dividends paid on the LESOP shares, $8, $59 and $55 were used in 2007, 2006 and 2005, respectively, to service LESOP debt. The amount in 2006 included $28 of LESOP debt service that was scheduled for payment on the first business day of January 2007 and was paid in late December 2006. In addition, the company made contributions in 2005 of $98 to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2007 or 2006 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, 2007 and 2006, were as follows:

Thousands	**2007**	2006
Allocated shares	**20,506**	21,827
Unallocated shares	**7,365**	8,316
Total LESOP shares	**27,871**	30,143

Note 20 Employee Benefit Plans Continued

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2007, the trust contained 14.2 million shares of Chevron treasury stock. The company intends to continue to pay its obligations under the benefit plans. 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 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.

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, 2007 and 2006, trust assets of $69 and $98, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans Chevron has two incentive plans, the Management Incentive Plan (MIP) and the Long-Term Incentive Plan (LTIP), for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by the recipients by conversion to stock units or other investment fund alternatives. Aggregate charges to expense for MIP were $184, $180 and $155 in 2007, 2006 and 2005, respectively. Awards under LTIP consist of stock options and other share-based compensation that are described in Note 21 below.

Through 2007 the company had a program that provided eligible employees, other than those covered by MIP and LTIP, with an annual cash bonus if the company achieves certain financial and safety goals. Charges for the program were $431, $329 and $324 in 2007, 2006 and 2005, respectively. Effective in 2008, this program was modified to mirror the design of MIP and both were combined into a single plan named the Chevron Incentive Plan (CIP).

Note 21

Stock Options and Other Share-Based Compensation

Effective July 1, 2005, the company adopted the provisions of Financial Accounting Standards Board Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation*.

The company adopted FAS 123R using the modified prospective method and, accordingly, results for prior periods were

not restated. Refer to Note 1, beginning on page FS-32, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123R for the full year 2005.

For 2007, 2006 and 2005, compensation expense for stock options was $146 ($95 after tax), $125 ($81 after tax) and $65 ($42 after tax), respectively. In addition, compensation expense for stock appreciation rights, performance units and restricted stock units was $205 ($133 after tax), $113 ($73 after tax) and $59 ($39 after tax) for 2007, 2006 and 2005, respectively. There were no significant stock-based compensation costs that were capitalized at December 31, 2007 and 2006.

Cash received in payment for option exercises under all share-based payment arrangements for 2007, 2006 and 2005 was $445, $444 and $297, respectively. Actual tax benefits realized for the tax deductions from option exercises were $94, $91 and $71 for 2007, 2006 and 2005, respectively.

Cash paid to settle performance units and stock appreciation rights was $88, $68 and $110 for 2007, 2006 and 2005, respectively. Cash paid in 2005 included $73 for Unocal awards paid under change-in-control plan provisions.

The company presents the tax benefits of deductions from the exercise of stock options as financing cash inflows in the Consolidated Statement of Cash Flows. In 2006, the company implemented the transition method of FASB Staff Position FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, for calculating the beginning balance of the pool of excess tax benefits related to employee compensation and determining the subsequent impact on the pool of employee awards that were fully vested and outstanding upon the adoption of FAS 123R. The company s reported tax expense for the period subsequent to the implementation of FAS 123R was not affected by this election. Refer to Note 3, on page FS-35, for information on excess tax benefits reported on the company s Statement of Cash Flows.

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.

Stock options and stock appreciation rights granted under the LTIP extend for 10 years from grant date. Effective with options granted in June 2002, one-third of each award vests on the first, second and third anniversaries of the date of grant. Prior to this change, options vested one year after the date of grant.

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Note 21 Stock Options and Other Share-Based Compensation
Continued

Performance units granted under the LTIP settle in cash at the end of a three-year performance period. Settlement amounts are based on achievement of performance targets relative to major competitors over the period, and payments are indexed to the company s stock price.

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 granted 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. Awards issued prior to 2004 generally may be exercised for up to three years after termination of employment (depending upon the terms of the individual award agreements) or the original expiration date, whichever is earlier. Awards issued since 2004 generally remained exercisable until the end of the normal option term if termination of employment occurred prior to August 10, 2007. Other awards issued under the Unocal Plans, including restricted stock, stock units, restricted stock units and performance shares, became vested at the acquisition date, and shares or cash were issued to recipients in accordance with change-in-control provisions of the plans.

The fair market values of stock options and stock appreciation rights granted in 2007, 2006 and 2005 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2007	2006	2005
Stock Options			
Expected term in years[1]	**6.3**	6.4	6.4
Volatility[2]	**22.0%**	23.7%	24.5%
Risk-free interest rate based on zero coupon U.S. treasury note	**4.5%**	4.7%	3.8%
Dividend yield	**3.2%**	3.1%	3.4%
Weighted-average fair value per option granted	**$ 15.27**	$ 12.74	$ 11.66
Restored Options			
Expected term in years[1]	**1.6**	2.2	2.1

Volatility[2]	**21.2%**	19.6%	18.6%
Risk-free interest rate based on zero coupon U.S. treasury note	**4.5%**	4.8%	3.8%
Dividend yield	**3.2%**	3.3%	3.4%
Weighted-average fair value per option granted	**$ 8.61**	$ 7.72	$ 6.09

Unocal Plans[3]	
Expected term in years[1]	4.2
Volatility[2]	21.6%
Risk-free interest rate based on zero coupon U.S. treasury note	3.9%
Dividend yield	3.4%
Weighted-average fair value per option granted	$ 21.48

[1] Expected term is based on historical exercise and post-vesting cancellation data.

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

[3] Represent options converted at the acquisition date.

A summary of option activity during 2007 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2007	55,945	$ 47.91		
Granted	12,848	$ 74.08		
Exercised	(14,340)	$ 51.92		
Restored	3,458	$ 80.45		
Forfeited	(554)	$ 72.36		
Outstanding at December 31, 2007	57,357	$ 54.50	6.3 yrs.	$ 2,227
Exercisable at December 31, 2007	35,540	$ 45.93	5.1 yrs.	$ 1,685

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2007, 2006 and 2005 was $423, $281 and $258, respectively.

Upon adoption of FAS 123R, the company elected to amortize newly issued graded awards on a straight-line basis over the requisite service period. In accordance with FAS 123R implementation guidance issued by the staff of the Securities and Exchange Commission, the company accelerates the vesting

Note 21 Stock Options and Other Share-Based Compensation
Continued

period for retirement-eligible employees in accordance with vesting provisions of the company s share-based compensation programs for awards issued after adoption of FAS 123R. As of December 31, 2007, there was $160 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 two years.

At January 1, 2007, the number of LTIP performance units outstanding was equivalent to 2,110,196 shares. During 2007, 931,200 units were granted, 784,364 units vested with cash proceeds distributed to recipients and 32,017 units were forfeited. At December 31, 2007, units outstanding were 2,225,015, and the fair value of the liability recorded for these instruments was $205. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 1 million equivalent shares as of December 31, 2007. A liability of $38 was recorded for these awards.

Broad-Based Employee Stock Options In addition to the plans described above, Chevron granted all eligible employees stock options or equivalents in 1998. The options vested in February 2000 and expired in February 2008. A total of 9,641,600 options were awarded with an exercise price of $38.16 per share.

The fair value of each option on the date of grant was estimated at $9.54 using the Black-Scholes model for the preceding 10 years. The assumptions used in the model, based on a 10-year average, were: a risk-free interest rate of 7 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

At January 1, 2007, the number of broad-based employee stock options outstanding was 1,306,059. During 2007, exercises of 637,044 shares and forfeitures of 16,300 shares reduced outstanding options to 652,715. As of December 31, 2007, these instruments had an aggregate intrinsic value of $36 and the remaining contractual term of these options was 0.1 year. The total intrinsic value of these options exercised during 2007, 2006 and 2005 was $30, $10 and $9, respectively.

Note 22

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-43 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 reduce 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 carries 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 2007, 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 that are subject to these indemnities must have arisen prior to December 2001. Claims must be asserted no later than February 2009 for Equilon indemnities and 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 has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described above 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. Under the indemnification agreement, the company s liability is unlimited until April 2022, when the indemnification expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of $200, which had not been reached as of December 31, 2007.

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

Note 22 Other Contingencies and Commitments   Continued

Securitization During 2007, the company completed the sale of its U.S. proprietary consumer credit card business and related receivables. This transaction included terminating the qualifying Special Purpose Entity (SPE) that was used to securitize associated retail accounts receivable.

Through the use of another qualifying SPE, the company had $675 of securitized trade accounts receivable related to its downstream business as of December 31, 2007. This arrangement has the effect of accelerating Chevron s collection of the securitized amounts. Chevron s total estimated financial exposure under this securitization at December 31, 2007, was $65. In the event that the SPE experiences major defaults in the collection of receivables, Chevron believes that it would have no additional loss exposure connected with third-party investments in this securitization.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating 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: 2008 $4,700; 2009 $3,300; 2010 $3,300; 2011 $1,900; 2012 $1,300; 2013 and after $4,900. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3,700 in 2007, $3,000 in 2006 and $2,100 in 2005.

Minority Interests The company has commitments of $204 related to minority interests in subsidiary companies.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations 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, 2007, was $1,539. Included in this balance were remediation activities of 240 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 2007 was $123. 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 2007 environmental reserves balance of $1,416, $864 related to approximately 2,000 sites for the company s U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining $552 was associated with various sites in the international downstream ($146), upstream ($267), chemicals ($105) and other ($34). 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 2007 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

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Note 22 Other Contingencies and Commitments   Continued

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 23 below for a discussion of the company s Asset Retirement Obligations.

Equity Redetermination For oil and 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 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.

Note 23

Asset Retirement Obligations

The company accounts for asset retirement obligations (ARO) in accordance with Financial Accounting Standards Board Statement (FASB) No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). This accounting standard applies to the fair value of a liability for an ARO that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition in certain circumstances: (1) the present value of a liability and offsetting asset for an ARO, (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. In 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations   An Interpretation of FASB Statement No. 143* (FIN 47), which was effective for the company on December 31, 2005. FIN 47 clarifies that the phrase   conditional asset retirement obligation,   as used in FAS 143, refers to a legal obligation to perform asset retirement activity for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the company. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Uncertainty about the timing and/or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an ARO. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. In adopting FIN 47, the company did not recognize any additional liabilities for conditional AROs due to an inability to reasonably estimate the fair value of those obligations because of their indeterminate settlement dates.

FAS 143 and FIN 47 primarily affect the company s accounting for crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical 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 and chemical 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 2007, 2006 and 2005:

	2007	2006	2005
Balance at January 1	**$ 5,773**	$ 4,304	$ 2,878
Liabilities assumed in the Unocal acquisition			1,216
Liabilities incurred	**178**	153	90
Liabilities settled	**(818)**	(387)	(172)
Accretion expense	**399***	275	187
Revisions in estimated cash flows	**2,721**	1,428	105
Balance at December 31	**$ 8,253**	$ 5,773	$ 4,304

*Includes $175 for revision to the ARO liability retained on properties that had been sold.

In the table above, the amounts for 2007 and 2006 associated with Revisions in estimated cash flows reflect increasing costs to abandon onshore and offshore wells, equipment and facilities,

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

Note 23 Asset Retirement Obligations Continued

including $1,128 in 2006 for the estimated costs to dismantle and abandon wells and facilities damaged by 2005 hurricanes in the Gulf of Mexico. The long-term portion of the $8,253 balance at the end of 2007 was $7,555.

Note 24

Other Financial Information

Net income in 2007 included gains of approximately $2,000 relating to the sale of nonstrategic properties. Of this amount, approximately $1,100 related to downstream assets and $680 related to the sale of the company s investment in Dynegy Inc.

Other financial information is as follows:

	Year ended December 31		
	2007	2006	2005
Total financing interest and debt costs	**$ 468**	$ 608	$ 542
Less: Capitalized interest	**302**	157	60
Interest and debt expense	**$ 166**	$ 451	$ 482
Research and development expenses	**$ 562**	$ 468	$ 316
Foreign currency effects*	**$ (352)**	$ (219)	$ (61)

*Includes $18, $15 and $(2) in 2007, 2006 and 2005, 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 $6,958 and $6,010 at December 31, 2007 and 2006, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO profits of $113, $82 and $34 were included in net income for the years 2007, 2006 and 2005, respectively.

Note 25

Earnings Per Share

Basic earnings per share (EPS) is based upon net income less preferred stock dividend requirements 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 21, Stock Options and Other Share-Based Compensation beginning on page FS-53). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2007	2006	2005
Basic EPS Calculation			
Income from operations	**$ 18,688**	$ 17,138	$ 14,099
Add: Dividend equivalents paid on stock units		1	2
Net income available to common stockholders Basic	**$ 18,688**	$ 17,139	$ 14,101
Weighted-average number of common shares outstanding	**2,117**	2,185	2,143
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**2,118**	2,186	2,144
Per share of common stock			
Net income Basic	**$ 8.83**	$ 7.84	$ 6.58
Diluted EPS Calculation			
Income from operations	**$ 18,688**	$ 17,138	$ 14,099
Add: Dividend equivalents paid on stock units		1	2
Add: Dilutive effects of employee stock-based awards			2
Net income available to common stockholders Diluted	**$ 18,688**	$ 17,139	$ 14,103
Weighted-average number of common shares outstanding	**2,117**	2,185	2,143
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**14**	11	11
Total weighted-average number of common shares outstanding	**2,132**	2,197	2,155
Per share of common stock			
Net income Diluted	**$ 8.77**	$ 7.80	$ 6.54

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Five-Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts	**2007**	2006	2005	2004	2003
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues[1,2]	**$ 214,091**	$ 204,892	$ 193,641	$ 150,865	$ 119,575
Income from equity affiliates and other income	**6,813**	5,226	4,559	4,435	1,702
Total Revenues and Other Income	**220,904**	210,118	198,200	155,300	121,277
Total Costs and Other Deductions	**188,737**	178,142	173,003	134,749	108,601
Income From Continuing Operations Before Income Taxes	**32,167**	31,976	25,197	20,551	12,676
Income Tax Expense	**13,479**	14,838	11,098	7,517	5,294
Income From Continuing Operations	**18,688**	17,138	14,099	13,034	7,382
Income From Discontinued Operations				294	44
Income Before Cumulative Effect of Changes in Accounting Principles	**18,688**	17,138	14,099	13,328	7,426
Cumulative effect of changes in accounting principles					(196)
Net Income	**$ 18,688**	$ 17,138	$ 14,099	$ 13,328	$ 7,230
Per Share of Common Stock[3]					
Income From Continuing Operations[4]					
Basic	**$ 8.83**	$ 7.84	$ 6.58	$ 6.16	$ 3.55
Diluted	**$ 8.77**	$ 7.80	$ 6.54	$ 6.14	$ 3.55
Income From Discontinued Operations					
Basic	**$**	$	$	$ 0.14	$ 0.02
Diluted	**$**	$	$	$ 0.14	$ 0.02
Cumulative Effect of Changes in Accounting Principles					
Basic	**$**	$	$	$	$ (0.09)
Diluted	**$**	$	$	$	$ (0.09)
Net Income[2]					
Basic	**$ 8.83**	$ 7.84	$ 6.58	$ 6.30	$ 3.48
Diluted	**$ 8.77**	$ 7.80	$ 6.54	$ 6.28	$ 3.48
Cash Dividends Per Share	**$ 2.26**	$ 2.01	$ 1.75	$ 1.53	$ 1.43

Balance Sheet Data (at December 31)

Current assets	**$ 39,377**	$ 36,304	$ 34,336	$ 28,503	$ 19,426
Noncurrent assets	**109,409**	96,324	91,497	64,705	62,044
Total Assets	**148,786**	132,628	125,833	93,208	81,470
Short-term debt	**1,162**	2,159	739	816	1,703
Other current liabilities	**32,636**	26,250	24,272	17,979	14,408
Long-term debt and capital lease obligations	**6,070**	7,679	12,131	10,456	10,894
Other noncurrent liabilities	**31,830**	27,605	26,015	18,727	18,170
Total Liabilities	**71,698**	63,693	63,157	47,978	45,175
Stockholders Equity	**$ 77,088**	$ 68,935	$ 62,676	$ 45,230	$ 36,295
[1] Includes excise, value-added and similar taxes:	**$ 10,121**	$ 9,551	$ 8,719	$ 7,968	$ 7,095
[2] Includes amounts in revenues for buy/sell contracts; associated costs are in Total Costs and Other Deductions. Refer also to Note 13, on page FS-42.	**$**	$ 6,725	$ 23,822	$ 18,650	$ 14,246

[3] Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

[4] The amount in 2003 includes a benefit of $0.08 for the company s share of a capital stock transaction of its Dynegy affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

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Supplemental Information on Oil and Gas Producing Activities
Unaudited

In accordance with Statement of FAS 69, *Disclosures About Oil and Gas Producing Activities,* this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations.
Tables V through VII present information on the company s estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Republic of the Congo and Democratic Republic of the Congo. The Asia-Pacific

Table I Costs Incurred in Exploration, Property Acquisitions and Development[1]

	Consolidated Companies											
	United States				International						Affiliated Companies	
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l	Total	TCO	Other
Year Ended Dec. 31, 2007												
Exploration												
Wells	**$ 4**	**$ 430**	**$ 18**	**$ 452**	**$ 202**	**$ 156**	**$ 3**	**$ 195**	**$ 556**	**$ 1,008**	**$**	**$ 7**
Geological and geophysical		**59**	**14**	**73**	**136**	**48**	**11**	**98**	**293**	**366**		
Rentals and other		**128**	**5**	**133**	**70**	**120**	**50**	**79**	**319**	**452**		
Total exploration	**4**	**617**	**37**	**658**	**408**	**324**	**64**	**372**	**1,168**	**1,826**		**7**
Property acquisitions[2]												
Proved	**10**	**220**	**13**	**243**	**5**	**92**		**(2)**	**95**	**338**		
Unproved	**35**	**75**	**3**	**113**	**8**	**35**		**24**	**67**	**180**		
Total property acquisitions	**45**	**295**	**16**	**356**	**13**	**127**		**22**	**162**	**518**		
Development[3]	**1,198**	**2,237**	**1,775**	**5,210**	**4,176**	**1,897**	**620**	**1,504**	**8,197**	**13,407**	**832**	**64**
Total Costs Incurred	**$ 1,247**	**$ 3,149**	**$ 1,828**	**$ 6,224**	**$ 4,597**	**$ 2,348**	**$ 684**	**$ 1,898**	**$ 9,527**	**$ 15,751**	**$ 832**	**$ 71**

Year Ended Dec. 31, 2006												
Exploration												
Wells	$	$ 493	$ 22	$ 515	$ 151	$ 121	$ 20	$ 246	$ 538	$ 1,053	$ 25	$
Geological and geophysical		96	8	104	180	53	12	92	337	441		
Rentals and other		116	16	132	48	140	58	50	296	428		
Total exploration		705	46	751	379	314	90	388	1,171	1,922	25	
Property acquisitions[2]												
Proved	6	152		158	1	10		15	26	184		581
Unproved	1	47	10	58		1		135	136	194		
Total property acquisitions	7	199	10	216	1	11		150	162	378		581
Development[3]	686	1,632	868	3,186	2,890	1,788	460	1,019	6,157	9,343	671	25
Total Costs Incurred	$ 693	$ 2,536	$ 924	$ 4,153	$ 3,270	$ 2,113	$ 550	$ 1,557	$ 7,490	$ 11,643	$ 696	$ 606
Year Ended Dec. 31, 2005												
Exploration												
Wells	$	$ 452	$ 24	$ 476	$ 105	$ 38	$ 9	$ 201	$ 353	$ 829	$	$
Geological and geophysical		67		67	96	28	10	68	202	269		
Rentals and other		93	8	101	24	58	12	72	166	267		
Total exploration		612	32	644	225	124	31	341	721	1,365		
Property acquisitions[2]												
Proved Unocal		1,608	2,388	3,996	30	6,609	637	1,790	9,066	13,062		
Proved Other		6	10	16	2	2		12	16	32		
Unproved Unocal		819	295	1,114	11	2,209	821	38	3,079	4,193		
Unproved Other		17	6	23	67			28	95	118		
Total property acquisitions		2,450	2,699	5,149	110	8,820	1,458	1,868	12,256	17,405		
Development[3]	507	680	601	1,788	1,892	1,088	382	726	4,088	5,876	767	43
Total Costs Incurred	$ 507	$ 3,742	$ 3,332	$ 7,581	$ 2,227	$ 10,032	$ 1,871	$ 2,935	$ 17,065	$ 24,646	$ 767	$ 43

1

Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 23, Asset Retirement Obligations, beginning on page FS-57.

[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired in nonmonetary transactions.

[3] Includes $99, $160 and $160 costs incurred prior to assignment of proved reserves in 2007, 2006 and 2005, respectively.

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Supplemental Information on Oil and Gas Producing Activities   Continued

geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The international   Other geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and
other countries. 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, Angola and Russia. Refer to Note 11 beginning on page FS-40 for a discussion of the company s major equity affiliates.

Table II   Capitalized Costs Related to Oil and Gas Producing Activities

	Consolidated Companies										Affiliat	
	United States				International						Compani	
llions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l.	Total	TCO	Oth
Dec. 31, 2007												
proved perties	**$ 805**	**$ 892**	**$ 353**	**$ 2,050**	**$ 314**	**$ 2,639**	**$ 630**	**$ 1,015**	**$ 4,598**	**$ 6,648**	**$ 112**	**$**
oved properties l related ducing assets	**11,260**	**19,110**	**13,718**	**44,088**	**11,894**	**17,321**	**7,705**	**11,360**	**48,280**	**92,368**	**4,247**	**8**
pport equipment	**201**	**206**	**230**	**637**	**850**	**284**	**1,123**	**439**	**2,696**	**3,333**	**758**	
ferred bloratory wells		**406**	**7**	**413**	**368**	**293**	**148**	**438**	**1,247**	**1,660**		
her uncompleted jects	**308**	**3,128**	**573**	**4,009**	**6,430**	**2,049**	**593**	**1,421**	**10,493**	**14,502**	**1,633**	
oss Cap. Costs	**12,574**	**23,742**	**14,881**	**51,197**	**19,856**	**22,586**	**10,199**	**14,673**	**67,314**	**118,511**	**6,750**	**9**
proved perties uation	**741**	**57**	**35**	**833**	**201**	**221**	**39**	**427**	**888**	**1,721**	**23**	
oved producing perties preciation and oletion	**7,383**	**15,074**	**7,640**	**30,097**	**5,427**	**6,912**	**5,592**	**7,062**	**24,993**	**55,090**	**644**	**1**
pport equipment preciation	**133**	**92**	**124**	**349**	**464**	**144**	**571**	**261**	**1,440**	**1,789**	**267**	

cumulated ovisions	**8,257**	**15,223**	**7,799**	**31,279**	**6,092**	**7,277**	**6,202**	**7,750**	**27,321**	**58,600**	**934**	**1**
t Capitalized sts	**$ 4,317**	**$ 8,519**	**$ 7,082**	**$ 19,918**	**$ 13,764**	**$ 15,309**	**$ 3,997**	**$ 6,923**	**$ 39,993**	**$ 59,911**	**$ 5,816**	**$ 74**
Dec. 31, 2006												
proved perties	$ 770	$ 1,007	$ 370	$ 2,147	$ 342	$ 2,373	$ 707	$ 1,082	$ 4,504	$ 6,651	$ 112	$
oved properties d related ducing assets	9,960	18,464	12,284	40,708	9,943	15,486	7,110	10,461	43,000	83,708	2,701	1,09
pport equipment	189	212	226	627	745	240	1,093	364	2,442	3,069	611	
ferred ploratory wells		343	7	350	231	217	149	292	889	1,239		
her uncompleted jects	370	2,188		2,558	4,299	1,546	493	917	7,255	9,813	2,493	4
oss Cap. Costs	11,289	22,214	12,887	46,390	15,560	19,862	9,552	13,116	58,090	104,480	5,917	1,11
proved perties uation	738	52	29	819	189	74	14	337	614	1,433	22	
oved producing perties preciation and pletion	7,082	14,468	6,880	28,430	4,794	5,273	4,971	6,087	21,125	49,555	541	1
pport equipment preciation	125	111	130	366	400	102	522	238	1,262	1,628	242	
cumulated ovisions	7,945	14,631	7,039	29,615	5,383	5,449	5,507	6,662	23,001	52,616	805	1
t Capitalized sts	$ 3,344	$ 7,583	$ 5,848	$ 16,775	$ 10,177	$ 14,413	$ 4,045	$ 6,454	$ 35,089	$ 51,864	$ 5,112	$ 1,0

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

	Consolidated Companies										Affiliated Companies	
	United States				International							
illions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l.	Total	TCO	Othe
t Dec. 31, 2005												
nproved roperties	$ 769	$ 1,077	$ 397	$ 2,243	$ 407	$ 2,287	$ 645	$ 983	$ 4,322	$ 6,565	$ 108	$
roved properties nd related roducing assets	9,546	18,283	11,467	39,296	8,404	14,928	6,613	9,627	39,572	78,868	2,264	1,21
upport equipment	204	193	230	627	715	426	1,217	356	2,714	3,341	549	
eferred xploratory wells		284	5	289	245	154	173	248	820	1,109		
ther uncompleted rojects	149	782	209	1,140	2,878	790	427	946	5,041	6,181	2,332	
ross Cap. Costs	10,668	20,619	12,308	43,595	12,649	18,585	9,075	12,160	52,469	96,064	5,253	1,21
nproved roperties aluation	736	90	22	848	162	69		318	549	1,397	17	
roved producing roperties epreciation and epletion	6,818	14,067	6,049	26,934	4,266	4,016	4,105	5,720	18,107	45,041	460	9
upport equipment epreciation	140	119	149	408	317	88	680	222	1,307	1,715	213	
ccumulated rovisions	7,694	14,276	6,220	28,190	4,745	4,173	4,785	6,260	19,963	48,153	690	9
et Capitalized osts	$ 2,974	$ 6,343	$ 6,088	$ 15,405	$ 7,904	$ 14,412	$ 4,290	$ 5,900	$ 32,506	$ 47,911	$ 4,563	$ 1,12

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Supplemental Information on Oil and Gas Producing Activities
Continued

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 2007, 2006 and 2005 are shown in the following table. Net income from exploration and production activities as reported on page FS-38 reflects income taxes computed on an effective rate basis.
In accordance with FAS 69, 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-38.

	Consolidated Companies										Affiliate Compani	
	United States				International							
llions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int l.	Total	TCO	Oth
ar Ended Dec. , 2007												
venues from net oduction												
les	**$ 202**	**$ 1,555**	**$ 2,476**	**$ 4,233**	**$ 1,810**	**$ 6,192**	**$ 1,045**	**$ 3,012**	**$ 12,059**	**$ 16,292**	**$ 3,327**	**$ 1,29**
ansfers	**4,671**	**2,630**	**2,707**	**10,008**	**6,778**	**4,440**	**2,590**	**2,744**	**16,552**	**26,560**		
tal	**4,873**	**4,185**	**5,183**	**14,241**	**8,588**	**10,632**	**3,635**	**5,756**	**28,611**	**42,852**	**3,327**	**1,29**
oduction penses cluding taxes[2]	**(1,063)**	**(936)**	**(1,400)**	**(3,399)**	**(892)**	**(953)**	**(892)**	**(828)**	**(3,565)**	**(6,964)**	**(248)**	**(9**
xes other than income	**(91)**	**(53)**	**(378)**	**(522)**	**(49)**	**(292)**	**(2)**	**(58)**	**(401)**	**(923)**	**(31)**	**(16**
oved producing operties:												
preciation and oletion	**(300)**	**(1,143)**	**(833)**	**(2,276)**	**(646)**	**(1,668)**	**(623)**	**(980)**	**(3,917)**	**(6,193)**	**(127)**	**(9**
cretion pense[3]	**(92)**	**1**	**(167)**	**(258)**	**(33)**	**(36)**	**(21)**	**(27)**	**(117)**	**(375)**	**(1)**	**(**
ploration penses		**(486)**	**(25)**	**(511)**	**(267)**	**(225)**	**(61)**	**(259)**	**(812)**	**(1,323)**		
proved operties uation	**(3)**	**(102)**	**(27)**	**(132)**	**(12)**	**(150)**	**(30)**	**(120)**	**(312)**	**(444)**		
her income pense)[4]	**3**	**2**	**31**	**36**	**(447)**	**(302)**	**(197)**	**(722)**	**(1,668)**	**(1,632)**	**18**	**(**

sults before come taxes	**3,327**	**1,468**	**2,384**	**7,179**	**6,242**	**7,006**	**1,809**	**2,762**	**17,819**	**24,998**	**2,938**	**94**
come tax pense	**(1,204)**	**(531)**	**(864)**	**(2,599)**	**(4,907)**	**(3,456)**	**(841)**	**(1,624)**	**(10,828)**	**(13,427)**	**(887)**	**(46**
sults of oducing perations	**$ 2,123**	**$ 937**	**$ 1,520**	**$ 4,580**	**$ 1,335**	**$ 3,550**	**$ 968**	**$ 1,138**	**$ 6,991**	**$ 11,571**	**$ 2,051**	**$ 48**
ar Ended Dec. , 2006												
venues from net oduction												
les	$ 308	$ 1,845	$ 2,976	$ 5,129	$ 2,377	$ 4,938	$ 1,001	$ 2,814	$ 11,130	$ 16,259	$ 2,861	$ 59
ansfers	4,072	2,317	2,046	8,435	5,264	4,084	2,211	2,848	14,407	22,842		
tal	4,380	4,162	5,022	13,564	7,641	9,022	3,212	5,662	25,537	39,101	2,861	59
oduction penses cluding taxes	(889)	(765)	(1,057)	(2,711)	(640)	(740)	(728)	(664)	(2,772)	(5,483)	(202)	(4
xes other than income	(84)	(57)	(442)	(583)	(57)	(231)	(1)	(60)	(349)	(932)	(28)	(
oved producing operties:												
preciation and pletion	(275)	(1,096)	(763)	(2,134)	(579)	(1,475)	(666)	(703)	(3,423)	(5,557)	(114)	(3
cretion pense[3]	(11)	(80)	(39)	(130)	(26)	(30)	(23)	(49)	(128)	(258)	(1)	
ploration penses		(407)	(24)	(431)	(296)	(209)	(110)	(318)	(933)	(1,364)	(25)	
proved operties uation	(3)	(73)	(8)	(84)	(28)	(15)	(14)	(27)	(84)	(168)		
her income pense)[4]	1	(732)	254	(477)	(435)	(475)	50	385	(475)	(952)	8	(5
sults before come taxes	3,119	952	2,943	7,014	5,580	5,847	1,720	4,226	17,373	24,387	2,499	46
come tax pense	(1,169)	(357)	(1,103)	(2,629)	(4,740)	(3,224)	(793)	(2,151)	(10,908)	(13,537)	(750)	(17
sults of oducing perations	$ 1,950	$ 595	$ 1,840	$ 4,385	$ 840	$ 2,623	$ 927	$ 2,075	$ 6,465	$ 10,850	$ 1,749	$ 29

[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] Includes $10 costs incurred prior to assignment of proved reserves in 2007.

[3] Represents accretion of ARO liability. Refer to Note 23, Asset Retirement Obligations, beginning on page FS-57.

[4] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

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

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Year Ended Dec. 31, 2005												
Revenues from net production												
Sales	$ 337	$ 1,576	$ 3,174	$ 5,087	$ 2,142	$ 2,941	$ 539	$ 2,668	$ 8,290	$ 13,377	$ 2,307	$ 666
Transfers	3,497	2,127	1,395	7,019	3,615	3,179	1,986	2,607	11,387	18,406		
Total	3,834	3,703	4,569	12,106	5,757	6,120	2,525	5,275	19,677	31,783	2,307	666
Production expenses excluding taxes	(916)	(638)	(777)	(2,331)	(558)	(570)	(660)	(596)	(2,384)	(4,715)	(152)	(82)
Taxes other than on income	(65)	(41)	(384)	(490)	(48)	(189)	(1)	(195)	(433)	(923)	(27)	
Proved producing properties:												
Depreciation and depletion	(253)	(936)	(520)	(1,709)	(414)	(852)	(550)	(672)	(2,488)	(4,197)	(83)	(46)
Accretion expense[2]	(13)	(35)	(46)	(94)	(22)	(20)	(15)	(25)	(82)	(176)	(1)	
Exploration expenses		(307)	(13)	(320)	(117)	(90)	(26)	(190)	(423)	(743)		
Unproved properties valuation	(3)	(32)	(4)	(39)	(50)	(8)		(24)	(82)	(121)		
Other income (expense)[3]	2	(354)	(140)	(492)	(243)	(182)	182	280	37	(455)	(9)	8
Results before income taxes	2,586	1,360	2,685	6,631	4,305	4,209	1,455	3,853	13,822	20,453	2,035	546
Income tax expense	(913)	(482)	(953)	(2,348)	(3,430)	(2,264)	(644)	(1,938)	(8,276)	(10,624)	(611)	(186)
Results of Producing Operations	$ 1,673	$ 878	$ 1,732	$ 4,283	$ 875	$ 1,945	$ 811	$ 1,915	$ 5,546	$ 9,829	$ 1,424	$ 360

[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 23, Asset Retirement Obligations, beginning on page FS-57.

[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

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Supplemental Information on Oil and Gas Producing Activities
Continued

Table IV Results of Operations for Oil and Gas Producing Activities Unit Prices and Costs[1,2]

	Consolidated Companies										Affiliated Companies	
	United States				International							
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Year Ended Dec. 31, 2007												
Average sales prices												
Liquids, per barrel	**$ 62.61**	**$ 65.07**	**$ 62.35**	**$ 63.16**	**$ 69.90**	**$ 64.20**	**$ 61.05**	**$ 62.97**	**$ 65.40**	**$ 64.71**	**$ 62.47**	**$ 51.98**
Natural gas, per thousand cubic feet	**5.77**	**7.01**	**5.65**	**6.12**		**3.60**	**7.61**	**4.13**	**4.02**	**4.79**	**0.89**	**0.44**
Average production costs, per barrel	**13.23**	**12.32**	**12.62**	**12.72**	**7.26**	**3.96**	**14.28**	**6.96**	**6.54**	**8.58**	**3.98**	**3.56**
Year Ended Dec. 31, 2006												
Average sales prices												
Liquids, per barrel	$ 55.20	$ 60.35	$ 55.80	$ 56.66	$ 61.53	$ 57.05	$ 52.23	$ 57.31	$ 57.92	$ 57.53	$ 56.80	$ 37.26
Natural gas, per thousand cubic feet	6.08	7.20	5.73	6.29	0.06	3.44	7.12	4.03	3.88	4.85	0.77	0.36
Average production costs, per barrel	10.94	9.59	9.26	9.85	5.13	3.36	11.44	5.23	5.17	6.76	3.31	2.51

Year Ended Dec. 31, 2005												
Average sales prices												
Liquids, per barrel	$ 45.24	$ 48.80	$ 48.29	$ 46.97	$ 50.54	$ 45.88	$ 44.40	$ 48.61	$ 47.83	$ 47.56	$ 45.59	$ 45.89
Natural gas, per thousand cubic feet	6.94	8.43	6.90	7.43	0.04	3.59	5.74	3.31	3.48	5.18	0.61	0.26
Average production costs, per barrel	10.74	8.55	7.57	8.88	4.72	3.38	11.28	4.32	4.93	6.32	2.45	5.53

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

[2] Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

Table V Reserve Quantity Information

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 reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

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

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

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the executive vice president responsible for the company s worldwide exploration and production activities. All of the RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC coordinates 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: provide independent reviews of the business units recommended reserve changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual,* which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

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Table V Reserve Quantity Information   Continued

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 and the Executive 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 alignment with the *Corporate Reserves Manual.*

Reserve Quantities   At December 31, 2007, oil-equivalent reserves for the company s consolidated operations were 7.9 billion barrels. (Refer to the term Reserves on page E-24 for the definition of oil-equivalent reserves.) Approximately 28 percent of the total reserves were in the United States. For the company s interests in equity affiliates, oil-equivalent reserves were 2.9 billion barrels, 84 percent of which were associated with the company s 50 percent ownership in TCO.

Aside from the TCO operations, no single property accounted for more than 5 percent of the company s total oil-equivalent proved reserves. Fewer than 20 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 about 37 percent of the company s proved reserves total. These properties were geographically dispersed, located in the United States, South America, West Africa and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2007 were 2.2 billion barrels. Of this amount, 41 percent, 21 percent and 38 percent were located in California, the Gulf of Mexico and other U.S. areas, respectively.

In California, liquids reserves represented 94 percent of the total, 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.

In the Gulf of Mexico region, liquids represented approximately 66 percent of total oil-equivalent reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Costs include investments in wells, production platforms and other facilities, such as gathering lines and storage facilities.

In other U.S. areas, the reserves were split about equally between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO_2 injection.

The pattern of net reserve changes shown in the following tables, for the three years ending December 31, 2007, is 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, changes in oil and gas prices, OPEC constraints, geopolitical uncertainties, and civil unrest.

The company s estimated net proved oil and natural gas reserves and changes thereto for the years 2005, 2006 and 2007 are shown in the tables on pages FS-68 and FS-70.

Supplemental Information on Oil and Gas Producing Activities
Continued

Table V Reserve Quantity Information Continued

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

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of barrels	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Reserves at Jan. 1, 2005	1,011	294	432	1,737	1,833	676	698	567	3,774	5,511	1,994	468
Changes attributable to:												
Revisions	(23)	(6)	(11)	(40)	(29)	(56)	(108)	(6)	(199)	(239)	(5)	(19)
Improved recovery	57		4	61	67	4	42	29	142	203		
Extensions and discoveries		37	7	44	53	21	1	65	140	184		
Purchases[1]		49	147	196	4	287	20	65	376	572		
Sales[2]	(1)		(1)	(2)				(58)	(58)	(60)		
Production	(79)	(41)	(45)	(165)	(114)	(103)	(74)	(89)	(380)	(545)	(50)	(14)
Reserves at Dec. 31, 2005[3]	965	333	533	1,831	1,814	829	579	573	3,795	5,626	1,939	435
Changes attributable to:												
Revisions	(14)	7	7		(49)	72	61	(45)	39	39	60	24
Improved recovery	49		3	52	13	1	6	11	31	83		
Extensions and discoveries		25	8	33	30	6	2	36	74	107		
Purchases[1]	2	2		4	15			2	17	21		119
Sales[2]								(15)	(15)	(15)		
Production	(76)	(42)	(51)	(169)	(125)	(123)	(72)	(78)	(398)	(567)	(49)	(16)
Reserves at Dec. 31, 2006[3]	926	325	500	1,751	1,698	785	576	484	3,543	5,294	1,950	562
Changes attributable to:												
Revisions	**1**	**(1)**	**(5)**	**(5)**	**(89)**	**7**	**(66)**	**7**	**(141)**	**(146)**	**92**	**11**
Improved recovery	**6**		**3**	**9**	**7**	**3**	**1**		**11**	**20**		
Extensions and discoveries	**1**	**25**	**10**	**36**	**6**	**1**		**17**	**24**	**60**		

Purchases[1]	**1**	**9**		**10**						**10**		**316**
Sales[2]		**(8)**	**(1)**	**(9)**						**(9)**		**(432)**
Production	**(75)**	**(43)**	**(50)**	**(168)**	**(122)**	**(128)**	**(72)**	**(74)**	**(396)**	**(564)**	**(53)**	**(24)**
Reserves at Dec. 31, 2007[3,4]	**860**	**307**	**457**	**1,624**	**1,500**	**668**	**439**	**434**	**3,041**	**4,665**	**1,989**	**433**
Developed Reserves[5]												
At Jan. 1, 2005	832	192	386	1,410	990	543	490	469	2,492	3,902	1,510	188
At Dec. 31, 2005	809	177	474	1,460	945	534	439	416	2,334	3,794	1,611	196
At Dec. 31, 2006	749	163	443	1,355	893	530	426	349	2,198	3,553	1,003	311
At Dec. 31, 2007	**701**	**136**	**401**	**1,238**	**758**	**422**	**363**	**305**	**1,848**	**3,086**	**1,273**	**263**

1 Includes reserves acquired through nonmonetary transactions.

2 Includes reserves disposed of through nonmonetary transactions.

3 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-23 for the definition of a PSC). PSC-related reserve quantities are 26 percent, 30 percent and 29 percent for consolidated companies for 2007, 2006 and 2005, respectively.

4 Net reserve changes (excluding production) in 2007 consist of 97 million barrels of developed reserves and (162) million barrels of undeveloped reserves for consolidated companies and 299 million barrels of developed reserves and (312) million barrels of undeveloped reserves for affiliated companies.

5 During 2007, the percentages of undeveloped reserves at December 31, 2006, transferred to developed reserves were 8 percent and 24 percent for consolidated companies and affiliated companies, respectively.

Information on Canadian Oil Sands Net Proved Reserves Not Included Above:

In addition to conventional liquids and natural gas proved reserves, Chevron has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, Chevron views these reserves and their development as an integral part of total upstream operations. However, SEC regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 436 million barrels as of December 31, 2007. The oil sands reserves are not considered in the standardized measure of discounted future net cash flows for conventional oil and gas reserves, which is found on page FS-73.

Noteworthy amounts in the categories of liquids proved-reserve changes for 2005 through 2007 are discussed below:

Revisions In 2005, net revisions reduced reserves by 239 million and 24 million barrels for worldwide consolidated companies and equity affiliates, respectively. For consolidated companies, the net decrease was 199 million barrels in the international areas and 40 million barrels in the United States. The largest downward net revisions internationally were 108 million barrels in Indonesia and
53 million barrels in Kazakhstan, due primarily to the effect of higher year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. In the United States, the 40 million-barrel reduction was across many fields in each of the geographic sections. Most of the downward revision for affiliated companies was a 19 million-barrel reduction in Hamaca, attributable to revised government royalty provisions. For TCO, the downward effect of higher year-end prices was partially offset by increased reservoir performance.

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Table V Reserve Quantity Information Continued

In 2006, net revisions increased reserves by 39 million and 84 million barrels for worldwide consolidated companies and equity affiliates, respectively. International consolidated companies accounted for the net increase of 39 million barrels. The largest upward net revisions were 61 million barrels in Indonesia and 27 million barrels in Thailand. In Indonesia, the increase was the result of infill drilling and improved steamflood performance. The upward revision in Thailand reflected additional drilling and development activity during the year. These upward revisions were partially offset by reductions in reservoir performance in Nigeria and the United Kingdom, which decreased reserves by 43 million barrels and by 32 million barrels, respectively. Most of the upward revision for affiliated companies was related to a 60 million-barrel increase in TCO as a result of improved reservoir performance.

In 2007, net revisions decreased reserves by 146 million barrels for worldwide consolidated companies and increased reserves by 103 million barrels for equity affiliates. For consolidated companies, the largest downward net revisions were 89 million barrels in Africa and 66 million barrels in Indonesia. In Africa, the decrease was mainly based on field performance data for fields in Nigeria and the effect of higher year-end prices in Angola and the Republic of the Congo. In Indonesia, the decline also reflected the impact of higher year-end prices. Higher prices also resulted in downward revisions in Karachaganak and Azerbaijan. For equity affiliates, most of the upward revision was related to a 92 million-barrel increase for the Tengiz Field in TCO and an 11 million-barrel increase for Petroboscan in Venezuela, both as a result of improved reservoir performance. At TCO, the upward revision was tempered by the negative impact of higher year-end prices.

Improved Recovery In 2005, improved recovery increased liquids volumes worldwide by 203 million barrels for consolidated companies. International areas accounted for 142 million barrels of the increase. Indonesia added 42 million barrels due to improved performance. Reserve additions of 67 million barrels in Africa occurred primarily in Angola and resulted from infill drilling, wells workovers and secondary recovery from gas injection. Additions of 29 million barrels in the Other international area were mainly attributable to improved waterflood performance offshore eastern Canada. An increase of 61 million barrels occurred in the United States, primarily in California due to improved performance on a large heavy oil field under thermal recovery.

In 2006, improved recovery increased liquids volumes worldwide by 83 million barrels for consolidated companies. Reserves in the United States increased 52 million barrels, with California representing 49 million barrels of the total increase due to steamflood expansion and revised modeling activities. Internationally, improved recovery increased reserves by 31 million barrels, with no single country accounting for an increase of more than 10 million barrels.

In 2007, improved recovery increased liquids volumes by 20 million barrels worldwide. No addition was individually significant.

Extensions and Discoveries In 2005, extensions and discoveries increased liquids volumes worldwide by 184 million barrels for consolidated companies. The largest increase was 49 million barrels in Nigeria, reflecting new development drilling, including in the Agbami Field, among others. New field developments in Brazil contributed another 41 million barrels of discoveries. In the United States, the 44 million-barrel addition was associated mainly with the initial booking of reserves for the Blind Faith Field in the deepwater Gulf of Mexico.

In 2006, extensions and discoveries increased liquids volumes worldwide by 107 million barrels for consolidated companies. Reserves in Nigeria increased by 27 million barrels due in part to the initial booking of reserves for the Aparo Field. Additional drilling activities contributed 19 million barrels in the United Kingdom and 14 million barrels in Argentina. In the United States, the Gulf of Mexico added 25 million barrels, mainly the result of the initial booking of the Great White Field in the deepwater Perdido Fold Belt area.

In 2007, extensions and discoveries increased liquids volumes by 60 million barrels worldwide. The largest additions were 25 million barrels in the U.S. Gulf of Mexico, mainly for the deepwater Tahiti and Mad Dog fields.

Purchases In 2005, the acquisition of 572 million barrels of liquids related solely to the acquisition of Unocal in August. About three-fourths of the 376 million barrels acquired in the international areas were represented by volumes in Azerbaijan and Thailand. Most volumes acquired in the United States were in Texas and Alaska.

In 2006, acquisitions increased liquids volumes worldwide by 21 million barrels for consolidated companies and 119 million barrels for equity affiliates. For consolidated companies, the amount was mainly the result of new agreements in Nigeria, which added 13 million barrels of reserves. The other-equity-affiliates quantity reflects the result of the conversion of Boscan and LL-652 operations to joint stock companies in Venezuela.

In 2007, acquisitions of 316 million barrels for equity affiliates related to the formation of a new Hamaca equity affiliate in Venezuela.

Sales In 2005, sales of 58 million barrels in the Other international area related to the disposition of the former Unocal operations onshore in Canada.

In 2006, sales decreased reserves by 15 million barrels due to the conversion of the LL-652 risked service agreement to a joint stock company in Venezuela.

In 2007, affiliated company sales of 432 million barrels related to the dissolution of a Hamaca equity affiliate in Venezuela.

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Supplemental Information on Oil and Gas Producing Activities
Continued

Table V Reserve Quantity Information Continued

Net Proved Reserves of Natural Gas

	Consolidated Companies										Affiliated Companies	
	United States				International							
Billions of cubic feet	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
Reserves at Jan. 1, 2005	314	1,064	2,326	3,704	2,979	5,405	502	3,538	12,424	16,128	3,413	134
Changes attributable to:												
Revisions	21	(15)	(15)	(9)	211	(428)	(31)	243	(5)	(14)	(547)	49
Improved recovery	8			8	13			31	44	52		
Extensions and discoveries		68	99	167	25	118	5	55	203	370		
Purchases[1]		269	899	1,168	5	3,962	247	274	4,488	5,656		
Sales[2]			(6)	(6)				(248)	(248)	(254)		
Production	(39)	(215)	(350)	(604)	(42)	(434)	(77)	(315)	(868)	(1,472)	(79)	(2)
Reserves at Dec. 31, 2005[3]	304	1,171	2,953	4,428	3,191	8,623	646	3,578	16,038	20,466	2,787	181
Changes attributable to:												
Revisions	32	40	(102)	(30)	34	400	38	39	511	481	26	
Improved recovery	5			5	3			5	8	13		
Extensions and discoveries		111	157	268	11	510		10	531	799		
Purchases[1]	6	13		19		16			16	35		54
Sales[2]			(1)	(1)				(148)	(148)	(149)		
Production	(37)	(241)	(383)	(661)	(33)	(629)	(110)	(302)	(1,074)	(1,735)	(70)	(4)
Reserves at Dec. 31, 2006[3]	310	1,094	2,624	4,028	3,206	8,920	574	3,182	15,882	19,910	2,743	231
Changes attributable to:												
Revisions	**40**	**39**	**130**	**209**	**(141)**	**149**	**12**	**166**	**186**	**395**	**75**	**(2)**
Improved recovery								**1**	**1**	**1**		
Extensions and discoveries		**40**	**46**	**86**	**11**	**392**		**29**	**432**	**518**		

Purchases[1]	**2**	**19**	**29**	**50**		**91**			**91**	**141**		**211**
Sales[2]		**(39)**	**(37)**	**(76)**						**(76)**		**(175)**
Production	**(35)**	**(210)**	**(375)**	**(620)**	**(27)**	**(725)**	**(101)**	**(279)**	**(1,132)**	**(1,752)**	**(70)**	**(10)**
Reserves at Dec. 31, 2007[3,4]	**317**	**943**	**2,417**	**3,677**	**3,049**	**8,827**	**485**	**3,099**	**15,460**	**19,137**	**2,748**	**255**
Developed Reserves[5]												
At Jan. 1, 2005	252	937	2,191	3,380	1,108	3,701	271	2,273	7,353	10,733	2,584	63
At Dec. 31, 2005	251	977	2,794	4,022	1,346	4,819	449	2,453	9,067	13,089	2,314	85
At Dec. 31, 2006	250	873	2,434	3,557	1,306	4,751	377	1,912	8,346	11,903	1,412	144
At Dec. 31, 2007	**261**	**727**	**2,238**	**3,226**	**1,151**	**5,081**	**326**	**1,915**	**8,473**	**11,699**	**1,762**	**117**

[1] Includes reserves acquired through nonmonetary transactions.

[2] Includes reserves disposed of through nonmonetary transactions.

[3] Includes year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-23 for the definition of a PSC). PSC-related reserve quantities are 37 percent, 47 percent and 44 percent for consolidated companies for 2007, 2006 and 2005, respectively.

[4] Net reserve changes (excluding production) in 2007 consist of 1,548 billion cubic feet of developed reserves and (569) billion cubic feet of undeveloped reserves for consolidated companies and 403 billion cubic feet of developed reserves and (294) billion cubic feet of undeveloped reserves for affiliated companies.

[5] During 2007, the percentages of undeveloped reserves at December 31, 2006, transferred to developed reserves were 10 percent and 27 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2005 through 2007 are discussed below:

Revisions In 2005, reserves were revised downward by 14 billion cubic feet (BCF) for consolidated companies and 498 BCF for equity affiliates. For consolidated companies, negative revisions were 428 BCF in the Asia-Pacific region. Most of the decrease was attributable to one field in Kazakhstan, due mainly to the effects of higher year-end prices on variable-royalty provisions of the production-sharing contract. Reserves additions for consolidated companies totaled 211 BCF and 243 BCF in Africa and Other, respectively. The majority of the African region changes were in Angola, due to a revised forecast of fuel gas usage, and in Nigeria, from improved reservoir performance. The availability of third-party compression in Colombia accounted for most of the increase in the Other region. Revisions in the United States decreased reserves by 9 BCF, as nominal increases in the San Joaquin Valley were more than offset by decreases in the Gulf of Mexico and Other region. For the TCO affiliate in Kazakhstan, a reduction of 547 BCF reflects the updated forecast of future royalties payable and year-end price effects, partially offset by volumes added as a result of an updated assessment of reservoir performance.

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Table V Reserve Quantity Information   Continued

In 2006, revisions accounted for a net increase of 481 BCF for consolidated companies and 26 BCF for affiliates. For consolidated companies, net increases of 511 BCF internationally were partially offset by a 30 BCF downward revision in the United States. Drilling and development activities added 337 BCF of reserves in Thailand, while Kazakhstan added 200 BCF, largely due to development activity. Trinidad and Tobago increased 185 BCF, attributable to improved reservoir performance and a new contract for sales of natural gas. These additions were partially offset by downward revisions of 224 BCF in the United Kingdom and 130 BCF in Australia due to drilling results and reservoir performance. U.S.   Other   had a downward revision of 102 BCF due to reservoir performance, which was partially offset by upward revisions of 72 BCF in the Gulf of Mexico and California related to reservoir performance and development drilling. TCO had an upward revision of 26 BCF associated with additional development activity and updated reservoir performance.

In 2007, revisions increased reserves for consolidated companies by a net 395 BCF and increased reserves for affiliated companies by a net 73 BCF. For consolidated companies, net increases were 209 BCF in the United States and 186 BCF internationally. Improved reservoir performance for many fields in the United States contributed 130 BCF in the   Other   region, 40 BCF in California and 39 BCF in the Gulf of Mexico. Drilling activities added 360 BCF in Thailand and improved reservoir performance added 188 BCF in Trinidad and Tobago. These additions were partially offset by downward revisions of 185 BCF in Australia due to drilling results and 136 BCF in Nigeria due to field performance. Negative revisions due to the impact of higher prices were recorded in Azerbaijan and Kazakhstan. TCO had an upward revision of 75 BCF associated with improved reservoir performance and development activities. This upward revision was net of a negative impact due to higher year-end prices.

Extensions and Discoveries In 2005, consolidated companies increased reserves by 370 BCF, including 167 BCF in the United States and 118 BCF in the Asia-Pacific region. In the United States, 99 BCF was added in the   Other region and 68 BCF in the Gulf of Mexico, primarily due to drilling activities. The addition in Asia-Pacific resulted primarily from increased drilling in Kazakhstan.

In 2006, extensions and discoveries accounted for an increase of 799 BCF for consolidated companies, reflecting a 531 BCF increase outside the United States and a U.S. increase of 268 BCF. Bangladesh added 451 BCF, the result of development activity and field extensions, and Thailand added 59 BCF, the result of drilling activities. U.S.   Other contributed 157 BCF, approximately half of which was related to South Texas and the Piceance Basin, and the Gulf of Mexico added 111 BCF, partly due to the initial booking of reserves at the Great White Field in the deepwater Perdido Fold Belt area.

In 2007, extensions and discoveries accounted for an increase of 518 BCF worldwide. The largest addition was 330 BCF in Bangladesh, the result of drilling activities. Other additions were not individually significant.

Purchases In 2005, all except 7 BCF of the 5,656 BCF total purchases were associated with the Unocal acquisition. International reserve acquisitions were 4,488 BCF, with Thailand accounting for about half the volumes. Other significant volumes were added in Bangladesh and Myanmar.

In 2006, purchases of natural gas reserves were 35 BCF for consolidated companies, about evenly divided between the company s United States and international operations. Affiliated companies added 54 BCF of reserves, the result of conversion of an operating service agreement to a joint stock company in Venezuela.

In 2007, purchases of natural gas reserves were 141 BCF for consolidated companies, which included the acquisition of an additional interest in the Bibiyana Field in Bangladesh. Affiliated company purchases of 211 BCF related to the formation of a new Hamaca equity affiliate in Venezuela and an initial booking related to the Angola

LNG project.

Sales In 2005, sales of 248 BCF in the Other international region related to the disposition of former-Unocal s onshore properties in Canada.

In 2006, sales for consolidated companies totaled 149 BCF, mostly associated with the conversion of a risked service agreement to a joint stock company in Venezuela.

In 2007, sales were 76 BCF and 175 BCF for consolidated companies and equity affiliates, respectively. The affiliated company sales related to the dissolution of a Hamaca equity affiliate in Venezuela.

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Supplemental Information on Oil and Gas Producing Activities
Continued

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 FAS 69. Estimated future cash inflows from production are computed by applying year-end 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 arbitrary valuation prescribed under FAS 69 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.

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Table VI Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves Continued

	United States				International					Consolidated Companies	C
dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO
ber 31,											
m	**$ 75,201**	**$ 34,162**	**$ 52,775**	**$ 162,138**	**$ 132,450**	**$ 93,046**	**$ 35,020**	**$ 45,566**	**$ 306,082**	**$ 468,220**	**159,078**
luction	**(17,888)**	**(7,193)**	**(16,780)**	**(41,861)**	**(15,707)**	**(16,022)**	**(18,270)**	**(11,990)**	**(61,989)**	**(103,850)**	**(10,408)**
el. costs	**(3,491)**	**(3,011)**	**(1,578)**	**(8,080)**	**(11,516)**	**(8,263)**	**(4,012)**	**(3,468)**	**(27,259)**	**(35,339)**	**(8,580)**
me	**(19,112)**	**(8,507)**	**(12,221)**	**(39,840)**	**(74,172)**	**(26,838)**	**(5,796)**	**(15,524)**	**(122,330)**	**(162,170)**	**(39,575)**
ed ash	**34,710**	**15,451**	**22,196**	**72,357**	**31,055**	**41,923**	**6,942**	**14,584**	**94,504**	**166,861**	**100,515**
nual r timing d cash	**(17,204)**	**(4,438)**	**(9,491)**	**(31,133)**	**(14,171)**	**(17,117)**	**(2,702)**	**(4,689)**	**(38,679)**	**(69,812)**	**(64,519)**
zed let s	**$ 17,506**	**$ 11,013**	**$ 12,705**	**$ 41,224**	**$ 16,884**	**$ 24,806**	**$ 4,240**	**$ 9,895**	**$ 55,825**	**$ 97,049**	**$ 35,996**
ber 31,											
m	$ 48,828	$ 23,768	$ 38,727	$ 111,323	$ 97,571	$ 70,288	$ 30,538	$ 36,272	$ 234,669	$ 345,992	$ 104,069
luction	(14,791)	(6,750)	(12,845)	(34,386)	(12,523)	(13,398)	(16,281)	(10,777)	(52,979)	(87,365)	(7,796)
el. costs	(3,999)	(2,947)	(1,399)	(8,345)	(9,648)	(6,963)	(2,284)	(3,082)	(21,977)	(30,322)	(7,026)
	(10,171)	(4,764)	(8,290)	(23,225)	(53,214)	(20,633)	(5,448)	(11,164)	(90,459)	(113,684)	(25,212)

me											
ed ash	19,867	9,307	16,193	45,367	22,186	29,294	6,525	11,249	69,254	114,621	64,035
nual r timing d cash	(9,779)	(3,256)	(7,210)	(20,245)	(10,065)	(12,457)	(2,426)	(3,608)	(28,556)	(48,801)	(40,597)
zed Jet s	$ 10,088	$ 6,051	$ 8,983	$ 25,122	$ 12,121	$ 16,837	$ 4,099	$ 7,641	$ 40,698	$ 65,820	$ 23,438
ber 31,											
m	$ 50,771	$ 29,422	$ 50,039	$ 130,232	$ 101,912	$ 73,612	$ 32,538	$ 44,680	$ 252,742	$ 382,974	$ 97,707
luction	(15,719)	(5,758)	(12,767)	(34,244)	(11,366)	(12,459)	(18,260)	(11,908)	(53,993)	(88,237)	(7,399)
el. costs	(2,274)	(2,467)	(873)	(5,614)	(8,197)	(5,840)	(1,730)	(2,439)	(18,206)	(23,820)	(5,996)
me	(11,092)	(7,173)	(12,317)	(30,582)	(50,894)	(21,509)	(5,709)	(13,917)	(92,029)	(122,611)	(23,818)
ed ash	21,686	14,024	24,082	59,792	31,455	33,804	6,839	16,416	88,514	148,306	60,494
nual r timing d cash	(10,947)	(4,520)	(10,838)	(26,305)	(14,881)	(14,929)	(2,269)	(5,635)	(37,714)	(64,019)	(37,674)
zed Jet s	$ 10,739	$ 9,504	$ 13,244	$ 33,487	$ 16,574	$ 18,875	$ 4,570	$ 10,781	$ 50,800	$ 84,287	$ 22,820

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Supplemental Information on Oil and Gas Producing Activities
Continued

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.

	Consolidated Companies			Affiliated Companies		
Millions of dollars	**2007**	2006	2005	**2007**	2006	2005
Present Value at January 1	**$ 65,820**	$ 84,287	$ 48,134	**$ 26,535**	$ 26,769	$ 14,920
Sales and transfers of oil and gas produced net of production costs	**(34,957)**	(32,690)	(26,145)	**(4,084)**	(3,180)	(2,712)
Development costs incurred	**10,468**	8,875	5,504	**889**	721	810
Purchases of reserves	**780**	580	25,307	**7,711**	1,767	
Sales of reserves	**(425)**	(306)	(2,006)	**(7,767)**		
Extensions, discoveries and improved recovery less related costs	**3,664**	4,067	7,446			
Revisions of previous quantity estimates	**(7,801)**	7,277	(13,564)	**(1,333)**	(967)	(2,598)
Net changes in prices, development and production costs	**74,900**	(24,725)	61,370	**23,616**	(837)	19,205
Accretion of discount	**12,196**	14,218	8,160	**3,745**	3,673	2,055
Net change in income tax	**(27,596)**	4,237	(29,919)	**(7,554)**	(1,411)	(4,911)
Net change for the year	**31,229**	(18,467)	36,153	**15,223**	(234)	11,849
Present Value at December 31	**$ 97,049**	$ 65,820	$ 84,287	**$ 41,758**	$ 26,535	$ 26,769

EXHIBIT INDEX

Exhibit No.	Description
3.1	Restated Certificate of Incorporation of Chevron Corporation, dated May 1, 2007, filed as Exhibit 3.1 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007, and incorporated herein by reference.
3.2	By-Laws of Chevron Corporation, as amended January 30, 2008, filed as Exhibit 3.1 to Chevron Corporation s Current Report on Form 8-K dated February 1, 2008, and incorporated herein by reference.
4	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.
10.1	Chevron Corporation Non-Employee Directors Equity Compensation and Deferral Plan filed as Exhibit 10.1 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007, and incorporated herein by reference.
10.2	Management Incentive Plan of Chevron Corporation filed as Exhibit 10.3 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.
10.4	Chevron Corporation Long-Term Incentive Plan filed as Exhibit 10.4 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, and incorporated herein by reference.
10.6	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 7, 2005, and incorporated herein by reference.
10.7	Chevron Corporation Deferred Compensation Plan for Management Employees II filed as Exhibit 10.5 to Chevron Corporation s Current Report on Form 8-K dated December 6, 2006, 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	Chevron Corporation 1998 Stock Option Program for U.S. Dollar Payroll Employees, filed as Exhibit 10.12 to Chevron Corporation s Annual Report on Form 10-K for the year ended December 31, 2002, and incorporated herein by reference.
10.13	Summary of Chevron s Management and Incentive Plan Awards and Criteria, filed as Exhibit 10.13 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005, and incorporated herein by reference.
10.14	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.

Exhibit No.	Description
10.15	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.
10.16	Form of Notice of Grant under the Chevron Corporation Long-Term Incentive Plan, filed as Exhibit 10.1 to Chevron s Current Report on Form 8-K dated June 29, 2005, 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 10.2 to Chevron s Current Report on Form 8-K dated June 29, 2005, and incorporated herein by reference.
10.18	Chevron Corporation Retirement Restoration Plan, filed as Exhibit 10.18 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, and incorporated herein by reference.
10.19	Chevron Corporation ESIP Restoration Plan, filed as Exhibit 10.19 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, and incorporated herein by reference.
10.20	Form of Restricted Stock Unit Grant Agreement under the Chevron Corporation Long-Term Incentive Plan, filed as Exhibit 10.20 to Chevron Corporation s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, 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 to E-5).
23.1*	Consent of PricewaterhouseCoopers LLP (page E-6).
24.1 to 24.12*	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-19).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company s Chief Financial Officer (page E-20).
32.1*	Section 1350 Certification of the company s Chief Executive Officer (page E-21).
32.2*	Section 1350 Certification of the company s Chief Financial Officer (page E-22).
99.1*	Definitions of Selected Energy and Financial Terms (pages E-23 to E-25).

* 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.