UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 8-K

Current Report
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 13, 2010

Chevron Corporation
(Exact name of registrant as specified in its charter)

Delaware	001-00368	94-0890210
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

6001 Bollinger Canyon Road, San Ramon, CA	94583
(Address of principal executive offices)	(Zip Code)

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

None
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 8.01 Other Events

This Current Report on Form 8-K revises portions of the Annual Report on Form 10-K of Chevron Corporation ("the company") for the year ended December 31, 2009 to retrospectively reflect subsequent changes in the company's operating segments.

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

As a result of the changes described in the previous paragraph, descriptions of upstream and downstream activities and discussions of segment earnings contained in Management's Discussion and Analysis of Financial Condition and Results of Operations have been revised. In addition, the following notes to the financial statements have also been revised:

- Note 1, Summary of Significant Accounting Policies – references to operating segments within the disclosures have been revised.
- Note 8, Lease Commitments – table revised to reflect the segment changes.
- Note 11, Operating Segments and Geographic Data – includes discussion of the segment changes and revised tables.
- Note 12, Investments and Advances – table revised to reflect the segment changes.
- Note 13, Properties, Plant and Equipment – table revised to reflect the segment changes.
- Note 22, Other Contingencies and Commitments – discussion of environmental reserves by segment revised.
- Note 23, Asset Retirement Obligations – references to operating segments within the discussion have been revised.

The exhibits included under Item 9.01 of this Current Report on Form 8-K revise the following sections of the 2009 Annual Report on Form 10-K to reflect the subsequent change in our operating segments:

- Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations
- Part II, Item 8, Financial Statements and Supplementary Data

Part I, and the other items in Part II, of the company's 2009 Form 10-K have not been revised nor included in this Form 8-K. The significant upstream-enabling operations that have been reclassified from downstream to upstream were already described in Part I under the upstream operations they support, as well as separately in the downstream section. Chemicals operations were described in a separate section. The company believes deletion of duplicate disclosures of upstream-enabling operations or the relocation of the separate description of Chemicals operations is not necessary for investors to understand Chevron's businesses.

This Current Report on Form 8-K does not reflect events that occurred after February 25, 2010, the date of the company's 2009 Annual Report on Form 10-K, and does not modify or update disclosures in any way other than as required to reflect the effects of the changes to the company's reportable segments described above. This filing does not purport to update the information contained in the 2009 Form 10-K for any information, uncertainties, transactions, risks, events or trends occurring, or known to management. More current information is contained in the company's Form 10-Q for the period ended March 31, 2010 and other current reports on Form 8-K filed subsequent to February 25, 2010.

Attached as Exhibit 101 to this Current Report are documents formatted in XBRL (Extensible Business Reporting Language).

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

See Exhibits index included herewith.

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

This Current Report on Form 8-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,” “projects,” “believes,” “seeks,” “schedules,” “estimates,” “budgets” and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond the company’s control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of the Annual Report on Form 10-K filed on February 25, 2010. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude-oil and natural-gas prices; changing refining, marketing and chemical margins; actions of competitors or regulators; timing of exploration expenses; timing of crude-oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; the inability or failure of the company’s joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude-oil and natural-gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company’s net production or manufacturing facilities or delivery/transportation networks due to war, accidents, political events, civil unrest, severe weather or crude-oil production quotas that might be imposed by the Organization of Petroleum Exporting Countries; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental statutes, regulations and litigation; the potential liability resulting from other pending or future litigation; the company’s future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign-currency movements compared with the U.S. dollar; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; and the factors set forth under the heading “Risk Factors” on pages 30 through 32 in the 2009 Annual Report on Form 10-K. 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.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Dated: May 13, 2010

CHEVRON CORPORATION
(REGISTRANT)

/s/ Matthew J. Foehr

Matthew J. Foehr, Vice President and Comptroller
(Principal Accounting Officer and
Duly Authorized Officer)

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EXHIBIT INDEX

Exhibit Number	Description
23.1	Consent of PricewaterhouseCoopers LLP
99.1	Updated Items 7 and 8 of Part II of the Annual Report on Form 10-K of Chevron Corporation for the year ended December 31, 2009
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and is otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed."

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 of Chevron Corporation (No. 333-165122), and to the incorporation by reference in the Registration Statements on Form S-8 of Chevron Corporation (Nos. 333-26731, 333-162660, 333-152846, 333-102269, 333-72672, 333-21805, 333-21807, 333-21809, 333-46261, 333-105136, 333-122121, 333-02011, 333-127566, 333-127558, 333-127559, 333-127560, 333-127561, 333-127563, 333-127564, 333-127565, 333-127568, 333-128733, 333-128734, 333-127567, 333-127569, 333-127570), of our report dated February 25, 2010, except with respect to our opinion on the consolidated financial statements insofar as it relates to the effects of the change in the composition of reportable segments discussed in Note 11, as to which the date is May 13, 2010, relating to the consolidated financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Current Report on Form 8-K.

/s/ PricewaterhouseCoopers LLP
PRICEWATERHOUSECOOPERS LLP

San Francisco, California
May 13, 2010

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Key Financial Results

Millions of dollars, except per-share amounts	2009	2008	2007
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
– Basic	**$ 5.26**	$ 11.74	$ 8.83
– Diluted	**$ 5.24**	$ 11.67	$ 8.77
Dividends	**$ 2.66**	$ 2.53	$ 2.26
Sales and Other Operating Revenues	**$ 167,402**	$ 264,958	$ 214,091
Return on:			
Capital Employed	**10.6%**	26.6%	23.1%
Stockholders' Equity	**11.7%**	29.2%	25.6%

Earnings by Major Operating Area

Millions of dollars	2009	2008	2007
Upstream			
United States	**$ 2,262**	$ 7,147	$ 4,541
International	**8,670**	15,022	10,577
Total Upstream	**10,932**	22,169	15,118
Downstream			
United States	**(121)**	1,369	1,209
International	**594**	1,783	2,387
Total Downstream	**473**	3,152	3,596
All Other	**(922)**	(1,390)	(26)
Net Income Attributable to Chevron Corporation(1),(2)	**$ 10,483**	$ 23,931	$ 18,688
(1) Includes foreign currency effects:	**$ (744)**	$ 862	$ (352)

(2) Also referred to as "earnings" in the discussions that follow.

Refer to the "Results of Operations" section beginning on page 6 for a discussion of financial results by major operating area for the three years ended December 31, 2009.

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, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Zone between Saudi Arabia and Kuwait, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, the United States, Venezuela and Vietnam.

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

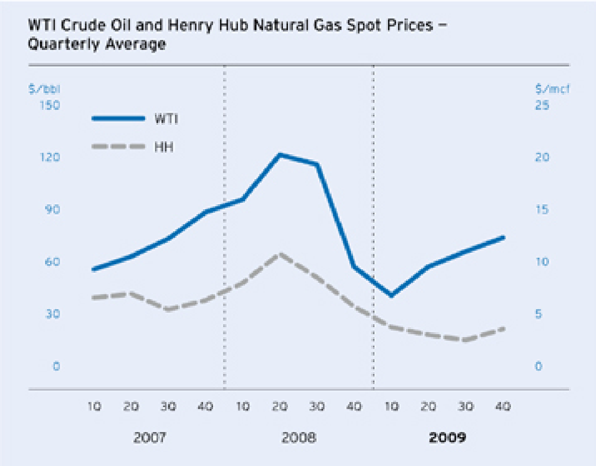
The company's operations, especially Upstream, can also be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. Civil unrest, acts of violence or strained relations between a government and the company or other governments may impact the company's operations or investments. Those developments have at times significantly affected the company's operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer attractive financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments. From time to time, certain governments have sought to renegotiate contracts or impose additional costs on the company. Governments may attempt to do so in the future. The company will continue to monitor these developments, take them into account in evaluating future investment opportunities, and otherwise seek to mitigate any risks to the company's current operations or future prospects.

The company also continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company's financial performance and growth. Refer to the "Results of Operations" section beginning on 6 for discussions of net gains on asset sales during 2009. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

In recent years, Chevron and the oil and gas industry at large experienced an increase in certain costs that exceeded the general trend of inflation in many areas of the world. This increase in costs affected the company's operating expenses and capital programs for all business segments, but particularly for Upstream. Softening of these cost pressures started in late 2008 and continued through most of 2009. Costs began to level out in the fourth quarter 2009. The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. (Refer to the "Upstream" section below for a discussion of the trend in crude-oil prices.)

The company continues to closely monitor developments in the financial and credit markets, the level of worldwide economic activity and the implications to the company of movements in prices for crude oil and natural gas. Management is taking these developments into account in the conduct of daily operations and for business planning. The company remains confident of its underlying financial strength to address potential challenges presented in this environment. (Refer also to the “Liquidity and Capital Resources” section beginning on 11.)



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

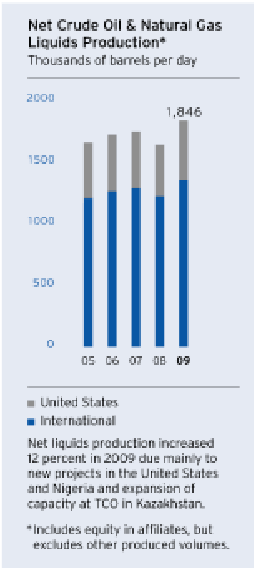
Upstream Earnings for the upstream segment are closely aligned with industry price levels for crude oil and natural gas. Crude-oil and natural-gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry 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 businesses. Besides the impact of the fluctuation in prices for crude oil and natural gas, the longer-term trend in earnings for the upstream segment is also a function of other factors, including the company’s ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms of contracts and changes in tax laws and regulations.

Price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can also be subject to external factors beyond the company’s control. External factors include not only the general level of inflation but also commodity prices and prices charged by the industry’s material and service providers, which can be affected by the volatility of the industry’s own supply-and-demand conditions for such materials and services. Capital and exploratory expenditures and operating expenses also can be affected by damage to production facilities caused by severe weather or civil unrest.

The chart at left shows the trend in benchmark prices for West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. Industry price levels for crude oil continued to be volatile during 2009, with prices for WTI ranging from $34 to $81 per barrel. The WTI price averaged $62 per barrel for the full-year 2009, compared to $100 in 2008. The decline in prices from 2008 was largely associated with a weakening in global economic conditions and a reduction in the demand for crude oil and petroleum products. As of mid-February 2010, the WTI price was about $77.

A differential in crude-oil prices exists between high-quality (high-gravity, low-sulfur) crudes and those of lower-quality (low-gravity, high-sulfur). The amount of the differential in any period is associated with the supply of heavy crude available versus the demand that is a function of the number of refineries that are able to process this lower-quality feedstock into light products (motor gasoline, jet fuel, aviation gasoline and diesel fuel). The differential remained narrow through 2009 as production declines in the industry have been mainly for lower-quality crudes.

Chevron produces or shares in the production of heavy crude oil in California, Chad, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page 10 for the company’s average U.S. and international crude-oil realizations.)



In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. In the United States, prices at Henry Hub averaged about $3.80 per thousand cubic feet (MCF) during 2009, compared with almost $9 during 2008. At December 31, 2009, and as of mid-February 2010, the Henry Hub spot price was about $5.70 and $5.50 per MCF, respectively. Fluctuations in the price for natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America and the level of inventory in underground storage. Weaker U.S. demand in 2009 was associated with the economic slowdown.

Certain international natural-gas markets in which the company operates have different supply, demand and regulatory circumstances, which historically have resulted in lower average sales prices for the company's production of natural gas in these locations. Chevron continues to invest in long-term projects in these locations to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets where greater demand results in higher prices. International natural-gas realizations averaged about $4.00 per MCF during 2009, compared with about $5.20 per MCF during 2008. Unlike prior years, these realizations compared favorably with those in the United States during 2009, primarily as a result of the deterioration of U.S. supply-and-demand conditions resulting from the economic slowdown. (See page 10 for the company's average natural gas realizations for the U.S. and international regions.)

The company's worldwide net oil-equivalent production in 2009 averaged 2.70 million barrels per day. About one-fifth of the company's net oil-equivalent production in 2009 occurred in the OPEC-member countries of Angola, Nigeria and Venezuela and in the Partitioned Zone between Saudi Arabia and Kuwait. For the year 2009, the company's net oil production was reduced by an average of 20,000 barrels per day due to quotas imposed by OPEC. All of the imposed curtailments took place during the first half of the year. At the December 2009 meeting, members of OPEC supported maintaining production quotas in effect since December 2008.

The company estimates that oil-equivalent production in 2010 will average approximately 2.73 million barrels per day. This estimate is subject to many factors and uncertainties, including additional quotas that may be imposed by OPEC, price effects on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, changes in fiscal terms or restrictions on the scope of company operations, delays in project startups, fluctuations in demand for natural gas in various markets, weather conditions that may shut in production, civil unrest, changing geopolitics, or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and, for new large-scale projects, the time lag between initial exploration and the beginning of production. Investments in upstream projects generally begin well in advance of the start of the associated crude-oil and natural-gas production. A significant majority of Chevron's upstream investment is made outside the United States.

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

Refer to Table V beginning on page FS-69 in our 2009 Form 10-K for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2007 and each year-end from 2007 through 2009, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2009.

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, additives for fuels and lubricant oils, and petrochemicals. Industry margins are sometimes volatile and can be affected by the global and regional supply-and-demand balance for refined products and petrochemicals, and by changes in the prices of crude oil and natural gas, the feedstocks used in manufacturing refined petroleum products and petrochemicals, respectively. Industry margins can also be influenced by inventory levels, geopolitical events, cost of materials and services, refinery or chemical-plant capacity utilization, maintenance programs and disruptions at refineries or chemical facilities resulting from unplanned outages due to severe weather, fires or other operational events.

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

The company's most significant refined-products marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia, southern Africa and the United Kingdom. Chevron operates or has significant ownership interests in refineries in each of these areas except Latin America. The company completed sales of marketing businesses during 2009 in certain countries in Latin America and Africa. The company plans to discontinue, by mid-2010, sales of Chevron- and Texaco-branded motor fuels in the mid-Atlantic and other eastern states, where the company sold to retail customers through approximately 1,100 stations and to commercial and industrial customers through supply arrangements. Sales in these markets represent approximately 8 percent of the company's total U.S. retail fuel sales volumes. Additionally, in January 2010, the company sold the rights to the Gulf trademark in the United States and its territories that it had previously licensed for use in the U.S. Northeast and Puerto Rico.

The company's refining and marketing margins in 2009 were generally weak due to challenging industry conditions, including a sharp drop in global demand reflecting the economic slowdown, excess refined-product supplies and surplus refining capacity. Given these conditions, in January 2010 the company announced to its employees that high-level evaluations of Chevron's refining and marketing organizations had been completed. These evaluations concluded that the company's downstream organization should be restructured to improve operating efficiency and achieve sustained improvement in financial performance. Details of the restructuring will be further developed over the next three to six months and may include exits from additional markets, dispositions of assets, reductions in the number of employees and other actions, which may result in gains or losses in future periods.

Refer to the "Results of Operations" section on pages 7 and 8 for additional discussion of the company's downstream operations.

Operating Developments

Key operating developments and other events during 2009 and early 2010 included the following:

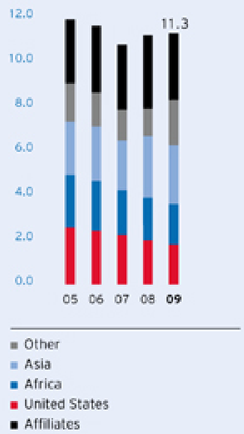
Upstream

Angola Production began at the 39.2 percent-owned and operated Mafumeira Norte offshore project in Block 0 and the 31 percent-owned and operated deepwater Tombua-Landana project in Block 14. Mafumeira Norte is expected to reach maximum total daily production of 42,000 barrels of crude oil in the third quarter 2010, and the Tombua-Landana project is expected to reach its maximum total production of approximately 100,000 barrels of crude oil per day in 2011. The company also discovered crude oil offshore in the 39.2 percent-owned and operated Block 0 concession, extending a trend of earlier discoveries in the Greater Vanza/Longui Area.

Australia The company and its partners reached final investment decision to proceed with the development of the Gorgon Project, located offshore Western Australia, in which Chevron has a 47.3 percent-owned and operated interest as of December 31, 2009. In addition, the company finalized long-term sales agreements for delivery of liquefied natural gas (LNG) from the Gorgon Project with four Asian customers, three of which also acquired an ownership interest in the project. Nonbinding Heads of Agreement (HOAs) with three additional Asian customers were also signed in late 2009 and early 2010 for delivery of LNG from the project. Negotiations continue to finalize binding sales agreements, which would bring LNG delivery commitments to a combined total of about 90 percent of Chevron's share of LNG from the project.

The company awarded front-end engineering and design contracts for the first phase of the Wheatstone natural gas project, also located offshore northwest Australia. The 75 percent-owned and operated facilities will have LNG processing capacity of 8.6 million metric tons per year and a co-located domestic natural-gas plant. The facilities will support development of Chevron's interests in the Wheatstone Field and nearby Iago Field. Agreements were signed with two companies to join the Wheatstone Project as combined 25 percent owners and suppliers of natural gas for the project's first two LNG trains. In addition, nonbinding HOAs were signed with two Asian customers to take delivery of 4.9 million metric tons per year of LNG from the project (about 60 percent of the total LNG available from the foundation project) and to acquire a 16.8 percent equity interest in the Wheatstone Field licenses and a 12.6 percent interest in the foundation natural gas processing facilities at the final investment decision.

Net Proved Reserves
Billions of BOE*



Net proved reserves for consolidated companies increased 5 percent in 2009, while affiliated companies' reserves were 8 percent lower.

*2009 includes barrels of oil-equivalent reserves for Canadian oil sands.

In May 2009 the company announced the successful completion of a well at the Clio prospect to further explore and appraise the 66.7 percent-owned Block WA-205-P. In 2009 and early 2010, the company also announced natural-gas discoveries at the Kentish Knock prospect in the 50 percent-owned Block WA-365-P, the Achilles and Satyr prospects in the 50 percent-owned Block WA-374-P and the Yellowglen prospect in the 50 percent-owned WA-268-P Block. All prospects are Chevron-operated. Proved reserves have not been recognized for these discoveries.

Brazil Production started at the 51.7 percent-owned and operated deepwater Frade Field, which is projected to attain maximum total production of 72,000 oil-equivalent barrels per day in 2011. Also, in early 2010 a final investment decision was reached to develop the 37.5 percent-owned, partner-operated Papa-Terra Field, where first production is expected in 2013. Project facilities are designed with a capacity to handle up to 140,000 barrels of crude oil per day.

Republic of the Congo Crude oil was discovered in the northern portion of the 31.5 percent-owned, partner-operated Moho-Bilondo deepwater permit area. This discovery follows two others made in 2007 in the same permit area.

Venezuela In February 2010, a Chevron-led consortium was named the operator of a heavy-oil project composed of three blocks in the Orinoco Oil Belt of eastern Venezuela.

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United States First oil was achieved at the 58 percent-owned and operated Tahiti Field in the deepwater Gulf of Mexico, reaching maximum total production of 135,000 barrels of oil-equivalent per day. The company also discovered crude oil at the Chevron-operated and 55 percent-owned Buckskin prospect in the deepwater Gulf of Mexico. The first appraisal well is scheduled to begin drilling in the second quarter 2010.

Downstream
The company sold businesses during 2009 in Brazil, Haiti, Nigeria, Benin, Cameroon, Republic of the Congo, Côte d'Ivoire, Togo, Kenya, Uganda, India, Italy, Peru and Chile.

Other
Common Stock Dividends The quarterly common stock dividend increased by 4.6 percent in July 2009, to $0.68 per share. 2009 was the 22nd consecutive year that the company increased its annual dividend payment.

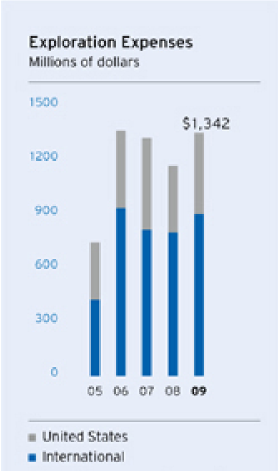
Common Stock Repurchase Program The company did not acquire any shares during 2009 under its $15 billion repurchase program, which began in 2007 and expires in September 2010. As of December 31, 2009, 119 million common shares had been acquired under this program for $10.1 billion.

Results of Operations
Major Operating Areas The following section presents the results of operations for the company's business segments – Upstream and Downstream – as well as for "All Other," 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. Earnings are also presented for the U.S. and international geographic areas of the Upstream and Downstream business segments. (Refer to Note 11, beginning on page 38, for a discussion of the company's "reportable segments," as defined in accounting standards for segment reporting (Accounting Standards Codification (ASC) 280)). This section should also be read in conjunction with the discussion in "Business Environment and Outlook" on pages 2 through 5.

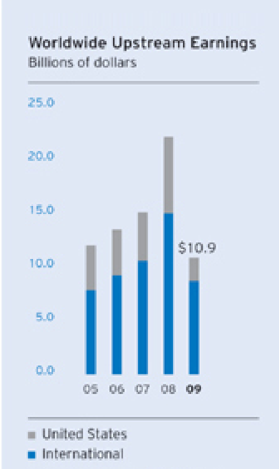
U.S. Upstream

Millions of dollars	**2009**	2008	2007
Earnings	**$ 2,262**	$ 7,147	$ 4,541

U.S upstream earnings of $2.3 billion in 2009 decreased $4.9 billion from 2008. Lower prices for crude oil and natural gas reduced earnings by about $5.2 billion between periods, and gains on asset sales declined by approximately $900 million. Partially offsetting these effects was a benefit of about $1.3 billion resulting from an increase in net oil-equivalent production. An approximate $600 million benefit to income from lower operating expenses was more than offset by higher depreciation expense. The benefit from lower operating expenses was largely associated with absence of charges for damages related to the 2008 hurricanes in the Gulf of Mexico.



Exploration expenses increased 15 percent from 2008 due mainly to higher well write-offs.



Earnings decreased in 2009 on lower average prices for crude oil and natural gas.

U.S upstream earnings of $7.1 billion in 2008 increased $2.6 billion from 2007. Higher average prices for crude oil and natural gas increased earnings by $3.1 billion between periods. Also contributing to the higher earnings were gains of approximately $1 billion on asset sales, including a $600 million gain on an asset-exchange transaction. Partially offsetting these benefits were adverse effects of about $1.6 billion associated with lower oil-equivalent production and higher operating expenses, which included approximately $400 million of expenses resulting from damage to facilities in the Gulf of Mexico caused by hurricanes.

The company's average realization for crude oil and natural gas liquids in 2009 was $54.36 per barrel, compared with $88.43 in 2008 and $63.16 in 2007. The average natural-gas realization was $3.73 per thousand cubic feet in 2009, compared with $7.90 and $6.12 in 2008 and 2007, respectively.

Net oil-equivalent production in 2009 averaged 717,000 barrels per day, up 6.9 percent from 2008 and down 3.5 percent from 2007. The increase between 2008 and 2009 was mainly due to the start-up of the Blind Faith Field in late 2008 and the Tahiti Field in the second quarter

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2009. The decrease between 2007 and 2008 was mainly due to normal field declines and the adverse impact of the hurricanes. The net liquids component of oil-equivalent production for 2009 averaged 484,000 barrels per day, up approximately 15 percent from 2008 and 5 percent compared with 2007. Net natural-gas production averaged 1.4 billion cubic feet per day in 2009, down approximately 7 percent from 2008 and about 18 percent from 2007.

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

International Upstream

Millions of dollars	**2009**	2008	2007
Earnings*	**$ 8,670**	$ 15,022	$ 10,577
*Includes foreign currency effects:	**$ (578)**	$ 937	$ (464)

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

Earnings of $15.0 billion in 2008 increased $4.4 billion from 2007. Higher prices for crude oil and natural gas increased earnings by $4.9 billion. Partially offsetting the benefit of higher prices was an impact of about $1.8 billion associated with a reduction of crude-oil sales volumes due to timing of certain cargo liftings and higher depreciation and operating expenses. Foreign-currency effects benefited earnings by $937 million in 2008, compared with a reduction to earnings of $464 million in 2007.

The company's average realization for crude oil and natural gas liquids in 2009 was $55.97 per barrel, compared with $86.51 in 2008 and $65.01 in 2007. The average natural-gas realization was $4.01 per thousand cubic feet in 2009, compared with $5.19 and $3.90 in 2008 and 2007, respectively.

Net oil-equivalent production of 1.99 million barrels per day in 2009 increased about 7 percent and 6 percent from 2008 and 2007, respectively. The volumes for each year included production from oil sands in Canada. Absent the impact of prices on certain production-sharing and variable-royalty agreements, net oil-equivalent production increased 4 percent in 2009 and 3 percent in 2008, when compared with prior years' production.

The net liquids component of oil-equivalent production was 1.4 million barrels per day in 2009, an increase of approximately 11 percent from 2008 and 5 percent from 2007. Net natural-gas production of 3.6 billion cubic feet per day in 2009 was down 1 percent and up 8 percent from 2008 and 2007, respectively.

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

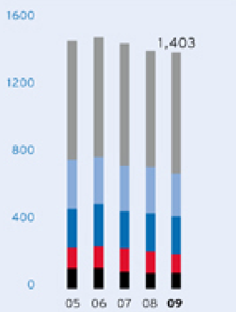
U.S. Downstream

Millions of dollars	**2009**	2008	2007
Earnings	**$ (121)**	$ 1,369	$ 1,209

U.S downstream operations lost $121 million in 2009, an earnings decrease of approximately $1.5 billion from 2008. Lower refined product margins resulted in an earnings decline of $1.7 billion. Partially offsetting the effects of lower refined product margins was a decrease in operating expenses, which benefited earnings by $300 million, and an increase of about $100 million in earnings from the 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem). The improvement for CPChem reflected lower utility and manufacturing costs, as well as the absence of an impairment recorded in 2008. These benefits more than offset lower margins on the sale of commodity chemicals.

Earnings of $1.4 billion in 2008 increased about $160 million from 2007 due mainly to improved margins on the sale of refined products and gains on derivative commodity instruments. Partially offsetting these benefits were lower earnings from chemical operations due mainly to lower sales volumes of commodity chemicals by CPChem. Operating expenses for the manufacturing, marketing and sales of refined products and petrochemicals increased in 2008 compared with 2007.

U.S. Gasoline & Other Refined-Product Sales
Thousands of barrels per day



- Gasoline
- Jet Fuel
- Gas Oils & Kerosene
- Residual Fuel Oil
- Other

Refined-product sales volumes decreased about 1 percent from 2008 on lower sales of jet fuel and fuel oil.

Worldwide Downstream Earnings*
Billions of dollars

- United States
- International

Downstream earnings decreased 85 percent from 2008 due to lower margins on the sale of refined products.

*Includes equity in affiliates

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Sales volumes of refined products were 1.40 million barrels per day in 2009, a decrease of 1 percent from 2008. The decline was associated with reduced demand for jet fuel and fuel oil, principally associated with the downturn in the U.S. economy. Sales volumes of refined products were 1.41 million barrels per day in 2008, a decrease of 3 percent from 2007. Branded gasoline sales volumes of 617,000 barrels per day in 2009 were up about 3 percent and down 2 percent from 2008 and 2007, respectively.

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

International Downstream

Millions of dollars	**2009**	2008	2007
Earnings*	**$ 594**	$ 1,783	$ 2,387
*Includes foreign currency effects:	**$ (191)**	$ 111	$ 106

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

Earnings in 2008 of $1.8 billion decreased about $600 million from 2007. Earnings in 2007 included gains of $1.1 billion on the sale of assets, which included refined products marketing assets and an interest in a refinery in the Benelux region of Europe. An additional $500 million improvement between years was associated with a benefit from gains on derivative commodity instruments, partially offset by the effect of lower margins from sales of refined products and higher operating expenses.

Refined-product sales volumes were 1.85 million barrels per day in 2009, about 8 percent lower than in 2008 due mainly to the effects of asset sales and lower demand. Refined-product sales volumes were 2.02 million barrels per day in 2008, about level with 2007.

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

All Other

Millions of dollars	**2009**	2008	2007
Net Charges*	**$ (922)**	$ (1,390)	$ (26)
*Includes foreign currency effects:	**$ 25**	$ (186)	$ 6

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, Inc. prior to its sale in May 2007.

Net charges in 2009 decreased $468 million from 2008 due to lower provisions for environmental remediation at sites that previously had been closed or sold, favorable foreign-currency effects and lower expenses for employee compensation and benefits. Net charges in 2008 increased $1.4 billion from 2007. Results in 2008 included net unfavorable corporate tax items and increased costs of environmental remediation. Foreign-currency effects also contributed to the increase in net charges from 2007 to 2008. 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.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2009**	2008	2007
Sales and other operating revenues	**$ 167,402**	$ 264,958	$ 214,091

Sales and other operating revenues decreased in 2009, due mainly to lower prices for crude oil, natural gas and refined products. Higher 2008 prices resulted in increased revenues compared with 2007.

Millions of dollars	**2009**	2008	2007
Income from equity affiliates	**$ 3,316**	$ 5,366	$ 4,144

Income from equity affiliates decreased in 2009 from 2008. Upstream-related affiliate income declined about $1.3 billion mainly due to lower earnings for Tengizchevroil (TCO) in Kazakhstan as a result of lower prices for crude oil. Downstream-related affiliate earnings were lower by approximately $1.0 billion primarily due to weaker margins and an unfavorable swing in foreign-currency effects. Income from equity affiliates increased in 2008 from 2007 largely due to improved upstream-related earnings at TCO as a result of higher prices for crude oil. Refer to Note 12, beginning on page 41, for a discussion of Chevron's investments in affiliated companies.

Millions of dollars	**2009**	2008	2007
Other income	**$ 918**	$ 2,681	$ 2,669

Other income of $918 million in 2009 included gains of approximately $1.3 billion on asset sales. Other income of $2.7 billion in 2008 and 2007 included net gains from asset sales of $1.3 billion and $1.7 billion, respectively. Interest income was approximately $95 million in 2009, $340 million in 2008 and $600 million in 2007. Foreign-currency effects reduced other income by $466 million in 2009 while increasing other income by $355 million in 2008 and reducing other income by $352 million in 2007. In addition, other income in 2008 included approximately $700 million in favorable settlements and other items.

Millions of dollars	**2009**	2008	2007
Purchased crude oil and products	**$ 99,653**	$ 171,397	$ 133,309

Crude oil and product purchases in 2009 decreased $71.7 billion from 2008 due to lower prices for crude oil, natural gas and refined products. Crude oil and product purchases in 2008 increased $38.1 billion from 2007 due to higher prices for crude oil, natural gas and refined products.

Millions of dollars	**2009**	2008	2007
Operating, selling, general and administrative expenses	**$ 22,384**	$ 26,551	$ 22,858

Operating, selling, general and administrative expenses in 2009 decreased approximately $4.2 billion from 2008 primarily due to $1.4 billion of lower fuel and transportation expenses; $800 million of decreased costs for contract labor and professional services; absence of uninsured 2008 hurricane-related charges of $700 million; a decrease of about $500 million for environmental remediation activities; $200 million of lower costs for materials; and $600 million for other items. Total expenses for 2008 were about $3.7 billion higher than 2007 primarily due to $1.2 billion of higher costs for employee and contract labor and professional services; $600 million of increased transportation expenses; $700 million of uninsured losses associated with hurricanes in the Gulf of Mexico in 2008; an increase of about $300 million for environmental remediation activities; $200 million from higher material expenses; and $700 million from increases for other items.

Millions of dollars	**2009**	2008	2007
Exploration expense	**$ 1,342**	$ 1,169	$ 1,323

Exploration expenses in 2009 increased from 2008 due mainly to higher amounts for well write-offs in the United States and international operations. Expenses in 2008 declined from 2007 mainly due to lower amounts for well write-offs for operations in the United States.

Millions of dollars	**2009**	2008	2007
Depreciation, depletion and amortization	**$ 12,110**	$ 9,528	$ 8,708

Depreciation, depletion and amortization expenses increased in 2009 from 2008 due to incremental production related to start-ups for upstream projects in the United States and Africa and higher depreciation rates for certain other oil and gas producing fields. The increase in 2008 from 2007 was largely due to higher depreciation rates for certain crude-oil and natural-gas producing fields, reflecting completion of higher-cost development projects and asset-retirement obligations.

Millions of dollars	**2009**	2008	2007
Taxes other than on income	**$ 17,591**	$ 21,303	$ 22,266

Taxes other than on income decreased in 2009 from 2008 mainly due to lower import duties for the company's downstream operations in the United Kingdom. Taxes other than on income decreased in 2008 from 2007 mainly due to lower import duties as a result of the effects of the 2007 sales of the company's Benelux refining and marketing businesses and a decline in import volumes in the United Kingdom.

Millions of dollars	**2009**	2008	2007
Interest and debt expense	**$ 28**	$ –	$ 166

Interest and debt expense increased in 2009 due to an increase in long-term debt. Interest and debt expense decreased in 2008 because all interest-related amounts were being capitalized.

Millions of dollars	2009	2008	2007
Income tax expense	**$ 7,965**	$ 19,026	$ 13,479

Effective income tax rates were 43 percent in 2009, 44 percent in 2008 and 42 percent in 2007. The rate was lower in 2009 than in 2008 mainly due to the effect in 2009 of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity-affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates. The rate was higher in 2008 compared with 2007 primarily due to a greater proportion of income earned in tax jurisdictions with higher income tax rates. In addition, the 2007 period included a relatively low effective tax rate on the sale of the company's investment in Dynegy common stock and the sale of downstream assets in Europe. Refer also to the discussion of income taxes in Note 15 beginning on page 44.

Selected Operating Data[1,2]

	2009	2008	2007
U.S. Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	**484**	421	460
Net Natural Gas Production (MMCFPD)[3]	**1,399**	1,501	1,699
Net Oil-Equivalent Production (MBOEPD)	**717**	671	743
Sales of Natural Gas (MMCFPD)	**5,901**	7,226	7,624
Sales of Natural Gas Liquids (MBPD)	**17**	15	25
Revenues From Net Production			
Liquids ($/Bbl)	**$ 54.36**	$ 88.43	$ 63.16
Natural Gas ($/MCF)	**$ 3.73**	$ 7.90	$ 6.12
International Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	**1,362**	1,228	1,296
Net Natural Gas Production (MMCFPD)[3]	**3,590**	3,624	3,320
Net Oil-Equivalent			
Production (MBOEPD)[4]	**1,987**	1,859	1,876
Sales of Natural Gas (MMCFPD)	**4,062**	4,215	3,792
Sales of Natural Gas Liquids (MBPD)	**23**	17	22
Revenues From Liftings			
Liquids ($/Bbl)	**$ 55.97**	$ 86.51	$ 65.01
Natural Gas ($/MCF)	**$ 4.01**	$ 5.19	$ 3.90
Worldwide Upstream			
Net Oil-Equivalent Production			
(MBOEPD)[3,4]			
United States	**717**	671	743
International	**1,987**	1,859	1,876
Total	**2,704**	2,530	2,619
U.S. Downstream			
Gasoline Sales (MBPD)[5]	**720**	692	728
Other Refined-Product Sales (MBPD)	**683**	721	729
Total Refined Product Sales (MBPD)	**1,403**	1,413	1,457
Sales of Natural Gas Liquids (MBPD)	**144**	144	135
Refinery Input (MBPD)	**899**	891	812
International Downstream			
Gasoline Sales (MBPD)[5]	**555**	589	581
Other Refined-Product Sales (MBPD)	**1,296**	1,427	1,446
Total Refined Product Sales (MBPD)[6]	**1,851**	2,016	2,027
Sales of Natural Gas Liquids (MBPD)	**88**	97	96
Refinery Input (MBPD)	**979**	967	1,021

1 Includes company share of equity affiliates.
2 MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day; MBOEPD – thousands of barrels of oil-equivalents per day; Bbl – Barrel; MCF = Thousands of cubic feet. Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of oil.
3 Includes natural gas consumed in operations (MMCFPD):

	2009	2008	2007
United States	**58**	70	65
International	**463**	450	433

4 Includes production from oil sands, Net (MBPD): **26** 27 27
5 Includes branded and unbranded gasoline.
6 Includes sales of affiliates (MBPD): **516** 512 492

Liquidity and Capital Resources

Cash, cash equivalents and marketable securities Total balances were $8.8 billion and $9.6 billion at December 31, 2009 and 2008, respectively. Cash provided by operating activities in 2009 was $19.4 billion, compared with $29.6 billion in 2008 and $25.0 billion in 2007.

Cash Provided by Operating Activities
Billions of dollars

Operating cash flows were approximately $10.3 billion lower than 2008 due to lower crude oil and natural gas prices.

Total Interest Expense & Total Debt at Year-End
Billions of dollars

Total Interest Expense (right scale)
Total Debt (left scale)

Total debt increased $1.6 billion during 2009 to $10.5 billion. Essentially all of the interest was capitalized as part of the cost of major projects.

Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.7 billion, $800 million and $300 million in 2009, 2008 and 2007, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.6 billion in 2009, $1.5 billion in 2008 and $3.3 billion in 2007.

Restricted cash of $123 million and $367 million associated with various capital-investment projects at December 31, 2009 and 2008, respectively, was invested in short-term marketable securities and recorded as “Deferred charges and other assets” on the Consolidated Balance Sheet.

Dividends Dividends paid to common stockholders were approximately $5.3 billion in 2009, $5.2 billion in 2008 and $4.8 billion in 2007. In July 2009, the company increased its quarterly common stock dividend by 4.6 percent to $0.68 per share.

Debt and capital lease obligations Total debt and capital lease obligations were $10.5 billion at December 31, 2009, up from $8.9 billion at year-end 2008.

The $1.6 billion increase in total debt and capital lease obligations during 2009 included the net effect of a $5 billion public bond issuance, a $350 million issuance of tax-exempt Gulf Opportunity Zone bonds, a $3.2 billion decrease in commercial paper, and a $400 million payment of principal for Texaco Capital Inc. bonds that matured in January 2009. 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 $4.6 billion at December 31, 2009, down from $7.8 billion at year-end 2008. Of these amounts, $4.2 billion and $5.0 billion were reclassified to long-term at the end of each period, respectively. At year-end 2009, settlement of these obligations was not expected to require the use of working capital in 2010, 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 2009, the company had $5.1 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, 2009. In addition, the company has an automatic shelf registration statement that expires in March 2010 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company. The company intends to file a new shelf registration statement when the current one expires.

The company has outstanding public bonds issued by Chevron Corporation, Chevron Corporation Profit Sharing/ Savings Plan Trust Fund, Texaco Capital Inc. and Union Oil Company of California. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard and Poor’s Corporation and Aa1 by Moody’s Investors Service. The company’s U.S. commercial paper is rated A-1+ by Standard and Poor’s and P-1 by Moody’s. All of these ratings denote high-quality, investment-grade securities.

The company’s future debt level is dependent primarily on results of operations, the capital-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.

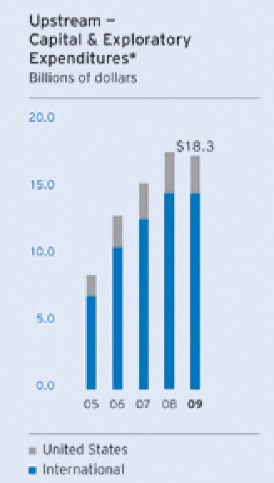
Common stock repurchase program In September 2007, the company authorized the acquisition of up to $15 billion of its common shares at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. The program is for a period of up to three years (expiring in 2010) and may be discontinued at any time. The company did not acquire any shares during 2009 and does not plan to acquire any shares in the first quarter 2010. From the inception of the program, the company has acquired 119 million shares at a cost of $10.1 billion.

Capital and Exploratory Expenditures

			2009			2008			2007
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream	**$ 3,294**	**$ 15,002**	**$ 18,296**	$ 5,648	$ 12,713	$ 18,361	$ 4,595	$ 11,305	$ 15,900
Downstream	**2,087**	**1,449**	**3,536**	2,457	1,332	3,789	1,757	1,595	3,352
All Other	**402**	**3**	**405**	618	7	625	768	6	774
Total	**$ 5,783**	**$ 16,454**	**$ 22,237**	$ 8,723	$ 14,052	$ 22,775	$ 7,120	$ 12,906	$ 20,026
Total, Excluding Equity in Affiliates	**$ 5,558**	**$ 15,094**	**$ 20,652**	$ 8,241	$ 12,228	$ 20,469	$ 6,900	$ 10,790	$ 17,690

Capital and exploratory expenditures Total expenditures for 2009 were $22.2 billion, including $1.6 billion for the company's share of equity-affiliate expenditures and $2 billion for the extension of an upstream concession. In 2008 and 2007, expenditures were $22.8 billion and $20.0 billion, respectively, including the company's share of affiliates' expenditures of $2.3 billion in both periods.

Of the $22.2 billion of expenditures in 2009, over 80 percent, or $18.3 billion, is related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2008 and 2007. International upstream accounted for over 80 percent of the worldwide upstream investment in 2009 and about
70 percent in 2008 and 2007, reflecting the company's continuing focus on opportunities available outside the United States.



Exploration and production expenditures were about the same as 2008, reflecting the capital-intensive phase of many significant projects.

*Includes equity in affiliates

The company estimates that in 2010, capital and exploratory expenditures will be $21.6 billion, including $1.6 billion of spending by affiliates. Over 80 percent of the total, or $18.0 billion, is budgeted for exploration and production activities, with $13.9 billion of this amount for projects outside the United States. Spending in 2010 is primarily targeted for exploratory prospects in the U.S. Gulf of Mexico and major development projects in Angola, Australia, Brazil, Canada, China, Nigeria, Thailand and the U.S. Gulf of Mexico. Also included is funding for base business improvements, focused appraisals in core hydrocarbon basins, and construction of a gas-to-liquids facility in support of associated upstream projects.

Worldwide downstream spending in 2010 is estimated at $3.1 billion, with about $1.7 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and South Korea.

Investments in technology and other corporate businesses in 2010 are budgeted at $500 million. Technology investments include projects related to unconventional hydrocarbon technologies, oil and gas reservoir management, and gas-fired and renewable power generation.

Noncontrolling interests The company had noncontrolling interests of $647 million and $469 million at December 31, 2009 and 2008, respectively. Distributions to noncontrolling interests totaled $71 million and $99 million in 2009 and 2008, respectively.

Pension Obligations In 2009, the company's pension plan contributions were $1.7 billion (including $1.5 billion to the U.S. plans and $200 million to the international plans). The company estimates contributions in 2010 will be approximately $900 million ($600 million for the U.S. plans and $300 million for the international plans). Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in "Critical Accounting Estimates and Assumptions," beginning on page 18.

Financial Ratios

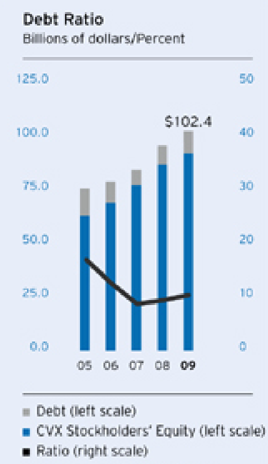
Financial Ratios

			At December 31
	2009	2008	2007
Current Ratio	**1.4**	1.1	1.2
Interest Coverage Ratio	**62.3**	166.9	69.2
Debt Ratio	**10.3%**	9.3%	8.6%

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 2009, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $5.5 billion.

Interest Coverage Ratio – income before income tax expense, plus interest and debt expense and amortization of capitalized interest, less net income attributable to noncontrolling interests, divided by before-tax interest costs. The company's interest coverage ratio in 2009 was lower than 2008 and 2007 due to lower before-tax income.

Debt Ratio – total debt as a percentage of total debt plus Chevron Corporation Stockholders' Equity. The increase in 2009 over 2008 and 2007 was primarily due to the increase in debt as a result of the $5 billion issuance of public bonds in 2009.



The ratio of total debt to total debt-plus-Chevron Corporation Stockholders' Equity increased to 10.3 percent at the end of 2009 due to the issuance of $5 billion in public bonds.

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

Direct Guarantee

Millions of dollars			Commitment Expiration by Period		
	Total	2010	2011–2012	2013–2014	After 2014
Guarantee of non-consolidated affiliate or joint-venture obligation	$ 613	$ –	$ 38	$ 77	$ 498

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

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300 million. Through the end of 2009, the company had paid $48 million under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. In February 2009, Shell delivered a letter to the company purporting to preserve unmatured claims for certain Equilon indemnities. The letter itself provides no estimate of the ultimate claim amount. Management does not believe this letter or any other information provides a basis to estimate the amount, if any, of a range of loss or potential range of loss with respect to either the Equilon or the Motiva indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

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

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

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities 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: 2010 – $7.5 billion; 2011 – $4.3 billion; 2012 – $1.4 billion; 2013 – $1.4 billion; 2014 – $1.0 billion; 2015 and after – $4.1 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately

$8.1 billion in 2009, $5.1 billion in 2008 and $3.7 billion in 2007.

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

Contractual Obligations[1]

Millions of dollars			Payments Due by Period		
	Total	2010	2011–2012	2013–2014	After 2014
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 384	$ 384	$ –	$ –	$ –
Long-Term Debt[3]	9,829	–	5,743	2,041	2,045
Noncancelable Capital Lease Obligations	499	90	168	104	137
Interest	2,590	317	566	426	1,281
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	3,364	568	844	719	1,233
Throughput and Take-or-Pay Agreements	15,130	6,555	3,825	819	3,931
Other Unconditional Purchase Obligations[4]	4,617	1,024	1,906	1,538	149

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page 50.

2 Does not include amounts related to the company's income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates for the periods in which these liabilities may become payable. The company does not expect settlement of such liabilities will have a material effect on its results of operations, consolidated financial position or liquidity in any single period.

3 $4.2 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 2011–2012 period.

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

Financial and Derivative Instruments

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk discussed below do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2009 Annual Report on Form 10-K.

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

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of these activities were not material to the company's financial position, results of operations or cash flows in 2009.

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

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

Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes. The change in fair value from Chevron's derivative commodity instruments in 2009 was a quarterly average decrease of $168 million in total assets and a quarterly average decrease of $104 million in total liabilities.

The company uses a Value-at-Risk (VaR) model to estimate the potential loss in fair value on a single day from the effect of adverse changes in market conditions on derivative commodity instruments held or issued, which are recorded on the balance sheet at December 31, 2009, as derivative commodity instruments in accordance with accounting standards for derivatives (ASC 815). VaR is the maximum loss not to be exceeded within a given probability or confidence level over a given period of time. The company's VaR model uses the Monte Carlo simulation method that involves generating hypothetical scenarios from the specified probability distribution and constructing a full distribution of a portfolio's potential values.

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

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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 the 95 percent/one-day VaR for each of the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2009 and 2008. The lower amounts in 2009 were primarily associated with a decrease in price volatility for these commodities during the year.

Millions of dollars	**2009**	2008
Crude Oil	**$ 17**	$ 39
Natural Gas	**4**	5
Refined Products	**19**	45

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

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Historically, under the terms of the swaps, net cash settlements were 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, if any, may be accounted for as fair – value hedges. Interest rate swaps related to floating-rate debt, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2009, the company had no interest rate swaps on floating-rate debt. The company's only interest rate swaps on fixed-rate debt matured in January 2009 and the company had no interest rate swaps on fixed-rate debt at year-end 2009.

Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements and long-term purchase agreements. Refer to Other Financial Information in Note 24 of the Consolidated Financial Statements, page 59, for further discussion. Management believes these agreements have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

Litigation and Other Contingencies

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 50 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

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

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

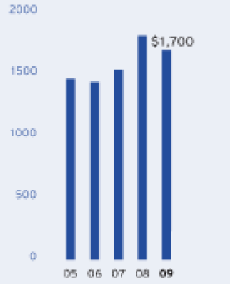
In April 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $8 billion, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer's report also asserted that an additional $8.3 billion could be assessed against Chevron for unjust enrichment. The engineer's report is not binding on the court. Chevron also believes that the engineer's work was performed and his report prepared in a manner contrary to law and in violation of the court's orders. Chevron submitted a rebuttal to the report in which it asked the court to strike the report in its entirety. In November 2008, the engineer revised the report and, without additional evidence, recommended an increase in the financial compensation for purported damages to a total of $18.9 billion and an increase in the assessment for purported unjust enrichment to a total of $8.4 billion. Chevron submitted a rebuttal to the revised report, which the court dismissed. In September 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case petitioned to be recused. In late September 2009, the judge was recused, and in October 2009, the full chamber of the provincial court affirmed the recusal, resulting in the appointment of a new judge. Chevron filed motions to annul all of the rulings made by the prior judge, but the new judge denied these motions. The court has completed most of the procedural aspects of the case and could render a judgment at any time. Chevron will continue a vigorous defense of any attempted imposition of liability.

In the event of an adverse judgment, Chevron would expect to pursue its appeals and vigorously defend against enforcement of any such judgment; therefore, the ultimate outcome – and any financial effect on Chevron – remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this case. Due to the defects associated with the engineer's report, management does not believe the report has any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

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

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

Year-End Environmental Remediation Reserves
Millions of dollars



Reserves for environmental remediation at the end of 2009 were down 6 percent from the prior year.

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	**2009**	2008	2007
Balance at January 1	**$1,818**	$1,539	$1,441
Net Additions	**351**	784	562
Expenditures	**(469)**	(505)	(464)
Balance at December 31	**$1,700**	$1,818	$1,539

Included in the $1,700 million year-end 2009 reserve balance were remediation activities at approximately 250 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 2009 was $185 million. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2009 environmental reserves balance of $1,515 million, $969 million related to the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facilities, and pipelines. The remaining $546 million was associated with various sites in international downstream ($107 million), upstream ($369 million) and other businesses ($70 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 and local regulations. No single remediation site at year-end 2009 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

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

Under accounting standards for asset retirement obligations (ASC 410), 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 $10.2 billion for asset retirement obligations at year-end 2009 related primarily to upstream properties.

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

Refer also to Note 23 on page 58, related to the company's asset retirement obligations and the discussion of "Environmental Matters" on page 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 44 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, 2009, the company had approximately $2.4 billion of suspended exploratory wells included in properties, plant and equipment, an increase of $317 million from 2008. The 2008 balance reflected an increase of $458 million from 2007.

The future trend of the company's exploration expenses can be affected by amounts associated with well write-offs, including wells that had been previously suspended pending determination as to whether the well had found reserves that could be classified as proved. The effect on exploration expenses in future periods of the $2.4 billion of suspended wells at year-end 2009 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 19, beginning on page 48, for additional discussion of suspended wells.

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 2009 at approximately $3.5 billion for its consolidated companies. Included in these expenditures were approximately $1.7 billion of environmental capital expenditures and $1.8 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

For 2010, total worldwide environmental capital expenditures are estimated at $2.1 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 and assumptions is according to the disclosure guidelines of the Securities and Exchange Commission (SEC), wherein:

1. the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and
2. the impact of the estimates and assumptions on the company's financial condition or operating performance is material.

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

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be "more likely than not." Another example is the estimation of crude-oil and natural-gas reserves under SEC rules, which, effective

December 31, 2009, require "...by analysis of geosciences and engineering data, (the reserves) can be estimated with reasonable certainty to be economically producible...under existing economic conditions" where existing economic conditions include prices based on the average price during the 12-month period. Refer to Table V, "Reserve Quantity Information," beginning on page FS-69 in our 2009 Form 10-K, for the changes in these estimates for the three years ending December 31, 2009, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page FS-77 in our 2009 Form 10-K for estimates of proved-reserve values for each of the three years ended December 31, 2009. Note 1 to the Consolidated Financial Statements, beginning on page 30, 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 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 30. The development and selection of accounting estimates and assumptions, including those deemed "critical," and the associated disclosures in this discussion have been discussed by management with the Audit Committee of the Board of Directors.

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

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

Note 21, beginning on page 50, includes information on the funded status of the company's pension and OPEB plans at the end of 2009 and 2008; the components of pension and OPEB expense for the three years ending December 31, 2009; and the underlying assumptions for those periods.

Pension and OPEB expense is reported on the Consolidated Statement of Income as "Operating expenses" or "Selling, general and administrative expenses" and applies to all business segments. The year-end 2009 and 2008 funded status, measured as the difference between plan assets and obligations, of each of the company's pension and OPEB plans is recognized on the Consolidated Balance Sheet. The differences related to overfunded pension plans are reported as a long-term asset in "Deferred charges and other assets." The differences associated with underfunded or unfunded pension and OPEB plans are reported as "Accrued liabilities" or "Reserves for employee benefit plans." Amounts yet to be recognized as components of pension or OPEB expense are reported in "Accumulated other comprehensive loss."

To estimate the long-term rate of return on pension assets, the company uses a process that incorporates actual historical asset-class returns and an assessment of expected future performance and takes into consideration external actuarial advice and asset-class factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies. The expected long-term rate of return on U.S. pension plan assets, which account for 69 percent of the company's pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2009, actual asset returns averaged 3.7 percent for this plan. The actual return for 2009 was 15.7 percent and was associated with the broad recovery in the financial markets.

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

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2009, the company selected a 5.3 percent discount rate for the major U.S. pension plan and 5.8 percent for its OPEB plan. These rates were selected based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2009. The discount rates at the end of 2008 and 2007 were 6.3 percent for both years for the U.S. pension and OPEB plans.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2009 was $1.1 billion. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the

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company's primary U.S. pension plan would have reduced total pension plan expense for 2009 by approximately $50 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 61 percent of the companywide pension obligation, would have reduced total pension plan expense for 2009 by approximately $150 million.

An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan reported on the Consolidated Balance Sheet. The total pension liability on the Consolidated Balance Sheet at December 31, 2009, for underfunded plans was approximately $3.8 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan would have reduced the plan obligation by approximately $300 million, which would have decreased the plan's underfunded status from approximately $1.6 billion to $1.3 billion. Other plans would be less underfunded as discount rates increase. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

In 2009, the company's pension plan contributions were $1.7 billion (including $1.5 billion to the U.S. plans). In 2010, the company estimates contributions will be approximately $900 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 2009 was $164 million and the total liability, which reflected the unfunded status of the plans at the end of 2009, was $3.1 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2009, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 69 percent of the companywide OPEB expense, would have decreased OPEB expense by approximately $11 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 84 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2009 by approximately $65 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 7 percent in 2010 and gradually drop to 5 percent for 2018 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2009, a 1 percent increase in the rates for the main U.S. OPEB plan, which accounted for 84 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 21, beginning on page 50, for information on the $6.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2009; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2010.

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 and Investments were recorded for the three years ending December 31, 2009. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

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

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

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

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

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

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is "more likely than not" (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 15 beginning on page 44. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2009.

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

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162 (FAS 168) In June 2009, the FASB issued FAS 168, which became effective for the company in the quarter ending September 30, 2009. This standard established the FASB Accounting Standards Codification (ASC) system as the single authoritative source of U.S. generally accepted accounting principles (GAAP) and superseded existing literature of the FASB, Emerging Issues Task Force, American Institute of CPAs and other sources. The ASC did not change GAAP, but organized the literature into about 90 accounting Topics. Adoption of the ASC did not affect the company's accounting.

Employer's Disclosures About Postretirement Benefit Plan Assets (FSP FAS 132(R)-1) In December 2008, the FASB issued FSP FAS 132(R)-1, which was subsequently codified into ASC 715, *Compensation – Retirement Benefits*, and became effective with the company's reporting at December 31, 2009. This standard amended and expanded the disclosure requirements for the plan assets of defined benefit pension and other postretirement plans. Refer to information beginning on page 50 in Note 21, Employee Benefits, for these disclosures.

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

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

Extractive Industries – Oil and Gas (ASC 932), Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03) In January 2010, the FASB issued ASU 2010-03, which became effective for the company on December 31, 2009. The standard amends certain sections of ASC 932, *Extractive Industries – Oil and Gas*, to align them with the requirements in the Securities and Exchange Commission's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the final rule). The final rule was issued on December 31, 2008. Refer to Table V – Reserve Quantity Information, beginning on page FS-69 in our 2009 Form 10-K, for additional information on the final rule and the impact of adoption.

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Quarterly Results and Stock Market Data
Unaudited

	2009				2008			
Millions of dollars, except per-share amounts	**4th Q**	**3rd Q**	**2nd Q**	**1st Q**	4th Q	3rd Q	2nd Q	1st Q
Revenues and Other Income								
Sales and other operating revenues[1]	**$ 47,588**	**$ 45,180**	**$ 39,647**	**$ 34,987**	$ 43,145	$ 76,192	$ 80,962	$ 64,659
Income from equity affiliates	**898**	**1,072**	**735**	**611**	886	1,673	1,563	1,244
Other income	**190**	**373**	**(177)**	**532**	1,172	1,002	464	43
Total Revenues and Other Income	**48,676**	**46,625**	**40,205**	**36,130**	45,203	78,867	82,989	65,946
Costs and Other Deductions								
Purchased crude oil and products	**28,606**	**26,969**	**23,678**	**20,400**	23,575	49,238	56,056	42,528
Operating expenses	**4,899**	**4,403**	**4,209**	**4,346**	5,416	5,676	5,248	4,455
Selling, general and administrative expenses	**1,330**	**1,177**	**1,043**	**977**	1,492	1,278	1,639	1,347
Exploration expenses	**281**	**242**	**438**	**381**	338	271	307	253
Depreciation, depletion and amortization	**3,156**	**2,988**	**3,099**	**2,867**	2,589	2,449	2,275	2,215
Taxes other than on income[1]	**4,583**	**4,644**	**4,386**	**3,978**	4,547	5,614	5,699	5,443
Interest and debt expense	**–**	**14**	**6**	**8**	–	–	–	–
Total Costs and Other Deductions	**42,855**	**40,437**	**36,859**	**32,957**	37,957	64,526	71,224	56,241
Income Before Income Tax Expense	**5,821**	**6,188**	**3,346**	**3,173**	7,246	14,341	11,765	9,705
Income Tax Expense	**2,719**	**2,342**	**1,585**	**1,319**	2,345	6,416	5,756	4,509
Net Income	**$ 3,102**	**$ 3,846**	**$ 1,761**	**$ 1,854**	$ 4,901	$ 7,925	$ 6,009	$ 5,196
Less: Net income attributable to noncontrolling interests	**32**	**15**	**16**	**17**	6	32	34	28
Net Income Attributable to Chevron Corporation	**$ 3,070**	**$ 3,831**	**$ 1,745**	**$ 1,837**	$ 4,895	$ 7,893	$ 5,975	$ 5,168
Per-Share of Common Stock								
Net Income Attributable to Chevron Corporation								
– Basic	**$ 1.54**	**$ 1.92**	**$ 0.88**	**$ 0.92**	$ 2.45	$ 3.88	$ 2.91	$ 2.50
– Diluted	**$ 1.53**	**$ 1.92**	**$ 0.87**	**$ 0.92**	$ 2.44	$ 3.85	$ 2.90	$ 2.48
Dividends	**$ 0.68**	**$ 0.68**	**$ 0.65**	**$ 0.65**	$ 0.65	$ 0.65	$ 0.65	$ 0.58
Common Stock Price Range – High[2]	**$ 79.64**	**$ 72.64**	**$ 72.67**	**$ 77.35**	$ 82.20	$ 99.08	$ 103.09	$ 94.61
– Low[2]	**$ 68.14**	**$ 61.40**	**$ 63.75**	**$ 56.46**	$ 57.83	$ 77.50	$ 86.74	$ 77.51
[1] Includes excise, value-added and similar taxes:	**$ 2,086**	**$ 2,079**	**$ 2,034**	**$ 1,910**	$ 2,080	$ 2,577	$ 2,652	$ 2,537

[2] End of day price.

The company’s common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 19, 2010, stockholders of record numbered approximately 195,000. There are no restrictions on the company’s ability to pay dividends.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2009 and December 31, 2008 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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) of the Company's 2009 Annual Report on Form 10-K (not presented herein) 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, 2009, 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 Management's Report on Internal Control Over Financial Reporting appearing on page FS-25 of the Company's 2009 Annual Report on Form 10-K (not presented herein). Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/PricewaterhouseCoopers LLP

San Francisco, California
February 25, 2010 except with respect to our opinion on the consolidated financial statements insofar as it relates to the effects of the change in the composition of reportable segments discussed in Note 11, as to which the date is May 13, 2010

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Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2009	2008	2007
Revenues and Other Income			
Sales and other operating revenues*	**$ 167,402**	$ 264,958	$ 214,091
Income from equity affiliates	**3,316**	5,366	4,144
Other income	**918**	2,681	2,669
Total Revenues and Other Income	**171,636**	273,005	220,904
Costs and Other Deductions			
Purchased crude oil and products	**99,653**	171,397	133,309
Operating expenses	**17,857**	20,795	16,932
Selling, general and administrative expenses	**4,527**	5,756	5,926
Exploration expenses	**1,342**	1,169	1,323
Depreciation, depletion and amortization	**12,110**	9,528	8,708
Taxes other than on income*	**17,591**	21,303	22,266
Interest and debt expense	**28**	–	166
Total Costs and Other Deductions	**153,108**	229,948	188,630
Income Before Income Tax Expense	**18,528**	43,057	32,274
Income Tax Expense	**7,965**	19,026	13,479
Net Income	**10,563**	24,031	18,795
Less: Net income attributable to noncontrolling interests	**80**	100	107
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688
Per-Share of Common Stock			
Net Income Attributable to Chevron Corporation			
– Basic	**$ 5.26**	$ 11.74	$ 8.83
– Diluted	**$ 5.24**	$ 11.67	$ 8.77
*Includes excise, value-added and similar taxes.	**$ 8,109**	$ 9,846	$ 10,121

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2009	2008	2007
Net Income	**$ 10,563**	$ 24,031	$ 18,795
Currency translation adjustment			
Unrealized net change arising during period	**60**	(112)	31
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	**2**	(6)	17
Reclassification to net income of net realized loss	**–**	–	2
Total	**2**	(6)	19
Derivatives			
Net derivatives (loss) gain on hedge transactions	**(69)**	139	(10)
Reclassification to net income of net realized (gain) loss	**(23)**	32	7
Income taxes on derivatives transactions	**32**	(61)	(3)
Total	**(60)**	110	(6)
Defined benefit plans			
Actuarial loss			
Amortization to net income of net actuarial loss	**575**	483	356
Actuarial (loss) gain arising during period	**(1,099)**	(3,228)	530
Prior service cost			
Amortization to net income of net prior service credits	**(65)**	(64)	(15)
Prior service (cost) credit arising during period	**(34)**	(32)	204
Defined benefit plans sponsored by equity affiliates	**65**	(97)	19
Income taxes on defined benefit plans	**159**	1,037	(409)
Total	**(399)**	(1,901)	685
Other Comprehensive (Loss) Gain, Net of Tax	**(397)**	(1,909)	729
Comprehensive Income	**10,166**	22,122	19,524
Comprehensive income attributable to noncontrolling interests	**(80)**	(100)	(107)
Comprehensive Income Attributable to Chevron Corporation	**$ 10,086**	$ 22,022	$ 19,417

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 2009	2008
Assets		
Cash and cash equivalents	**$ 8,716**	$ 9,347
Marketable securities	**106**	213
Accounts and notes receivable (less allowance: 2009 – $228; 2008 – $246)	**17,703**	15,856
Inventories:		
Crude oil and petroleum products	**3,680**	5,175
Chemicals	**383**	459
Materials, supplies and other	**1,466**	1,220
Total inventories	**5,529**	6,854
Prepaid expenses and other current assets	**5,162**	4,200
Total Current Assets	**37,216**	36,470
Long-term receivables, net	**2,282**	2,413
Investments and advances	**21,158**	20,920
Properties, plant and equipment, at cost	**188,288**	173,299
Less: Accumulated depreciation, depletion and amortization	**91,820**	81,519
Properties, plant and equipment, net	**96,468**	91,780
Deferred charges and other assets	**2,879**	4,711
Goodwill	**4,618**	4,619
Assets held for sale	**–**	252
Total Assets	**$ 164,621**	$ 161,165
Liabilities and Equity		
Short-term debt	**$ 384**	$ 2,818
Accounts payable	**16,437**	16,580
Accrued liabilities	**5,375**	8,077
Federal and other taxes on income	**2,624**	3,079
Other taxes payable	**1,391**	1,469
Total Current Liabilities	**26,211**	32,023
Long-term debt	**9,829**	5,742
Capital lease obligations	**301**	341
Deferred credits and other noncurrent obligations	**17,390**	17,678
Noncurrent deferred income taxes	**11,521**	11,539
Reserves for employee benefit plans	**6,808**	6,725
Total Liabilities	**72,060**	74,048
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	**–**	–
Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2009 and 2008)	**1,832**	1,832
Capital in excess of par value	**14,631**	14,448
Retained earnings	**106,289**	101,102
Accumulated other comprehensive loss	**(4,321)**	(3,924)
Deferred compensation and benefit plan trust	**(349)**	(434)
Treasury stock, at cost (2009 – 434,954,774 shares; 2008 – 438,444,795 shares)	**(26,168)**	(26,376)
Total Chevron Corporation Stockholders' Equity	**91,914**	86,648
Noncontrolling interests	**647**	469
Total Equity	**92,561**	87,117
Total Liabilities and Equity	**$ 164,621**	$ 161,165

See accompanying Notes to the Consolidated Financial Statements.

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Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2009	2008	2007
Operating Activities			
Net Income	**$ 10,563**	$ 24,031	$ 18,795
Adjustments			
Depreciation, depletion and amortization	**12,110**	9,528	8,708
Dry hole expense	**552**	375	507
Distributions less than income from equity affiliates	**(103)**	(440)	(1,439)
Net before-tax gains on asset retirements and sales	**(1,255)**	(1,358)	(2,315)
Net foreign currency effects	**466**	(355)	378
Deferred income tax provision	**467**	598	261
Net (increase) decrease in operating working capital	**(2,301)**	(1,673)	685
Increase in long-term receivables	**(258)**	(161)	(82)
Decrease (increase) in other deferred charges	**201**	(84)	(530)
Cash contributions to employee pension plans	**(1,739)**	(839)	(317)
Other	**670**	10	326
Net Cash Provided by Operating Activities	**19,373**	29,632	24,977
Investing Activities			
Capital expenditures	**(19,843)**	(19,666)	(16,678)
Proceeds and deposits related to asset sales	**2,564**	1,491	3,338
Net sales of marketable securities	**127**	483	185
Repayment of loans by equity affiliates	**336**	179	21
Net sales (purchases) of other short-term investments	**244**	432	(799)
Net Cash Used for Investing Activities	**(16,572)**	(17,081)	(13,933)
Financing Activities			
Net (payments) borrowings of short-term obligations	**(3,192)**	2,647	(345)
Proceeds from issuances of long-term debt	**5,347**	–	650
Repayments of long-term debt and other financing obligations	**(496)**	(965)	(3,343)
Cash dividends – common stock	**(5,302)**	(5,162)	(4,791)
Distributions to noncontrolling interests	**(71)**	(99)	(77)
Net sales (purchases) of treasury shares	**168**	(6,821)	(6,389)
Net Cash Used for Financing Activities	**(3,546)**	(10,400)	(14,295)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**114**	(166)	120
Net Change in Cash and Cash Equivalents	**(631)**	1,985	(3,131)
Cash and Cash Equivalents at January 1	**9,347**	7,362	10,493
Cash and Cash Equivalents at December 31	**$ 8,716**	$ 9,347	$ 7,362

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2009 Shares	2009 Amount	2008 Shares	2008 Amount	2007 Shares	2007 Amount
Preferred Stock	**–**	**$ –**	–	$ –	–	$ –
Common Stock	**2,442,677**	**$ 1,832**	2,442,677	$ 1,832	2,442,677	$ 1,832
Capital in Excess of Par						
Balance at January 1		**$ 14,448**		$ 14,289		$ 14,126
Treasury stock transactions		**183**		159		163
Balance at December 31		**$ 14,631**		$ 14,448		$ 14,289
Retained Earnings						
Balance at January 1		**$ 101,102**		$ 82,329		$ 68,464
Net income attributable to Chevron Corporation		**10,483**		23,931		18,688
Cash dividends on common stock		**(5,302)**		(5,162)		(4,791)
Adoption of new accounting standard for uncertain income tax positions		**–**		–		(35)
Tax benefit from dividends paid on unallocated ESOP shares and other		**6**		4		3
Balance at December 31		**$ 106,289**		$ 101,102		$ 82,329
Notes Receivable – Key Employees		**$ –**		$ –		$ (1)
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (171)**		$ (59)		$ (90)
Change during year		**60**		(112)		31
Balance at December 31		**$ (111)**		$ (171)		$ (59)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (3,909)**		$ (2,008)		$ (2,585)
Change to defined benefit plans during year		**(399)**		(1,901)		685
Adoption of new accounting standard for defined benefit pension and other postretirement plans		**–**		–		(108)
Balance at December 31		**$ (4,308)**		$ (3,909)		$ (2,008)
Unrealized net holding gain on securities						
Balance at January 1		**$ 13**		$ 19		$ –
Change during year		**2**		(6)		19
Balance at December 31		**$ 15**		$ 13		$ 19
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		**$ 143**		$ 33		$ 39
Change during year		**(60)**		110		(6)
Balance at December 31		**$ 83**		$ 143		$ 33
Balance at December 31		**$ (4,321)**		$ (3,924)		$ (2,015)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		**$ (194)**		$ (214)		$ (214)
Net reduction of ESOP debt and other		**85**		20		–
Balance at December 31		**(109)**		(194)		(214)
Benefit Plan Trust (Common Stock)	**14,168**	**(240)**	14,168	(240)	14,168	(240)
Balance at December 31	**14,168**	**$ (349)**	14,168	$ (434)	14,168	$ (454)
Treasury Stock at Cost						
Balance at January 1	**438,445**	**$ (26,376)**	352,243	$ (18,892)	278,118	$ (12,395)
Purchases	**85**	**(6)**	95,631	(8,011)	85,429	(7,036)
Issuances – mainly employee benefit plans	**(3,575)**	**214**	(9,429)	527	(11,304)	539
Balance at December 31	**434,955**	**$ (26,168)**	438,445	$ (26,376)	352,243	$ (18,892)
Total Chevron Corporation Stockholders' Equity at December 31		**$ 91,914**		$ 86,648		$ 77,088
Noncontrolling Interests		**$ 647**		$ 469		$ 204
Total Equity		**$ 92,561**		$ 87,117		$ 77,292

See accompanying Notes to the Consolidated Financial Statements.

Note 1

Summary of Significant Accounting Policies

General Upstream operations consist of primarily exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation, regasification, storage and marketing associated with natural gas; transporting crude oil by major international oil-export pipelines; and a gas-to-liquids project. Downstream operations relate primarily to refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and additives for fuels and lubricant oils.

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

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

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

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

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

Derivatives The majority of the company's activity in derivative commodity instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's commodity trading activity and foreign currency exposures, gains and losses from derivative instruments 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 is 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.

Properties, Plant and Equipment The successful efforts method is used for crude-oil and natural-gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for exploratory wells that have found crude-oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 19, beginning on page 48, for additional discussion of accounting for suspended exploratory well costs.

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

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value.

As required under accounting standards for asset retirement and environmental obligations (Accounting Standards Codification (ASC) 410), the fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 23, on page 58, relating to AROs.

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

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

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

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

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

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

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company's U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For crude-oil, natural-gas and mineral-producing properties, a liability for an ARO is made, following accounting standards for asset retirement and environmental obligations. Refer to Note 23, on page 58, for a discussion of the company's AROs.

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

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

Currency Translation The U.S. dollar is the functional currency for substantially all of the company's consolidated operations and those of its equity affiliates. For those operations, all gains and losses from currency 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 "Currency translation adjustment" on the Consolidated Statement of Equity.

Revenue Recognition Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized on the entitlement method. Excise, value-added and similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income on page 25. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in "Purchased crude oil and products" on the Consolidated Statement of Income.

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

Note 2

Noncontrolling Interests

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

Activity for the equity attributable to noncontrolling interests for 2009, 2008 and 2007 is as follows:

	2009	2008	2007
Balance at January 1	**$ 469**	$ 204	$ 209
Net income	**80**	100	107
Distributions to noncontrolling interests	**(71)**	(99)	(77)
Other changes, net	**169**	264	(35)
Balance at December 31	**$ 647**	$ 469	$ 204

Note 3

Equity

Retained earnings at December 31, 2009 and 2008, included approximately $8,122 and $7,951, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2009, about 94 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 342,000 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).

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Note 4

Information Relating to the Consolidated Statements of Cash Flows

	Year ended December 31		
	2009	2008	2007
Net (increase) decrease in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	**$ (1,476)**	$ 6,030	$ (3,867)
Decrease (increase) in inventories	**1,213**	(1,545)	(749)
Increase in prepaid expenses and other current assets	**(264)**	(621)	(370)
(Decrease) increase in accounts payable and accrued liabilities	**(1,121)**	(4,628)	4,930
(Decrease) increase in income and other taxes payable	**(653)**	(909)	741
Net (increase) decrease in operating working capital	**$ (2,301)**	$ (1,673)	$ 685
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
Income taxes	**$ 7,537**	$ 19,130	$ 12,340
Net sales of marketable securities consisted of the following gross amounts:			
Marketable securities sold	**$ 157**	$ 3,719	$ 2,160
Marketable securities purchased	**(30)**	(3,236)	(1,975)
Net sales of marketable securities	**$ 127**	$ 483	$ 185

In accordance with accounting standards for cash-flow classifications for stock options (ASC 718), the “Net (increase) decrease in operating working capital” includes reductions of $25, $106 and $96 for excess income tax benefits associated with stock options exercised during 2009, 2008 and 2007, respectively. These amounts are offset by an equal amount in “Net sales (purchases) of treasury shares.”

The “Net sales (purchases) of treasury shares” represents the cost of common shares purchased less the cost of shares issued for share-based compensation plans. Purchases totaled $6, $8,011 and $7,036 in 2009, 2008 and 2007, respectively. Purchases in 2008 and 2007 included shares purchased under the company’s common stock repurchase programs.

In 2009, “Net sales (purchases) of other short-term investments” consisted of $123 in restricted cash associated with capital-investment projects at the company’s Pascagoula, Mississippi refinery and the Angola liquefied-natural-gas project that was invested in short-term securities and reclassified from “Cash and cash equivalents” to “Deferred charges and other assets” on the Consolidated Balance Sheet. The company issued $350 and $650, in 2009 and 2007 respectively, of tax exempt Mississippi Gulf Opportunity Zone Bonds as a source of funds for Pascagoula Refinery projects.

The Consolidated Statement of Cash Flows for 2009 excludes changes to the Consolidated Balance Sheet that did not affect cash. In 2008, “Net sales (purchases) of treasury shares” excludes $680 of treasury shares acquired in exchange for a U.S. upstream property and $280 in cash. The carrying value of this property in “Properties, plant and equipment” on the Consolidated Balance Sheet was not significant. In 2008, a $2,450 increase in “Accrued liabilities” and a corresponding increase to “Properties, plant and equipment, at cost” were considered non-cash transactions and excluded from “Net (increase) decrease in operating working capital” and “Capital expenditures.” In 2009, the payments related to these “Accrued liabilities” were excluded from “Net (increase) decrease in operating working capital” and were reported as “Capital expenditures.” The amount is related to upstream operating agreements outside the United States. “Capital expenditures” in 2008 excludes a $1,400 increase in “Properties, plant and equipment” related to the acquisition of an additional interest in an equity affiliate that required a change to the consolidated method of accounting for the investment during 2008. This addition was offset primarily by reductions in “Investments and advances” and working capital and an increase in “Non-current deferred income tax” liabilities. Refer also to Note 23, on page 58, for a discussion of revisions to the company’s AROs that also did not involve cash receipts or payments for the three years ending December 31, 2009.

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

	Year ended December 31		
	2009	2008	2007
Additions to properties, plant and equipment[1]	**$ 16,107**	$ 18,495	$ 16,127
Additions to investments	**942**	1,051	881
Current-year dry-hole expenditures	**468**	320	418
Payments for other liabilities and assets, net[2]	**2,326**	(200)	(748)
Capital expenditures	**19,843**	19,666	16,678
Expensed exploration expenditures	**790**	794	816
Assets acquired through capital lease obligations and other financing obligations	**19**	9	196
Capital and exploratory expenditures, excluding equity affiliates	**20,652**	20,469	17,690
Company’s share of expenditures by equity affiliates	**1,585**	2,306	2,336
Capital and exploratory expenditures, including equity affiliates	**$ 22,237**	$ 22,775	$ 20,026

[1] Excludes noncash additions of $985 in 2009, $5,153 in 2008 and $3,560 in 2007.
[2] 2009 includes payments of $2,450 for accruals recorded in 2008.

Note 5

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

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

During 2008, Chevron implemented legal reorganizations in which certain Chevron subsidiaries transferred assets to or under CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the table below gives retroactive effect to the reorganizations as if they had occurred on January 1, 2007. However, the financial information in the following table may not reflect the financial position and operating results in the future or the historical results in the periods presented if the reorganization actually had occurred on that date. The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2009	2008	2007
Sales and other operating revenues	**$121,553**	$195,593	$153,574
Total costs and other deductions	**120,053**	185,788	147,509
Net income attributable to CUSA	**1,141**	7,318	5,191

	At December 31	
	2009	2008
Current assets	**$ 23,286**	$ 32,760
Other assets	**32,827**	31,806
Current liabilities	**16,098**	14,322
Other liabilities	**14,625**	14,049
Total CUSA net equity	**25,390**	36,195
Memo: Total debt	**$ 6,999**	$ 6,813

The amount for the years ended December 31, 2008, and December 31, 2007, for "Net income attributable to CUSA" and the balances at December 31, 2008, for "Other liabilities" and "Total CUSA net equity" have been adjusted by immaterial amounts associated with the allocation of income-tax liabilities among Chevron Corporation subsidiaries.

Note 6

Summarized Financial Data – Chevron Transport Corporation Ltd.

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

	Year ended December 31		
	2009	2008	2007
Sales and other operating revenues	**$ 683**	$1,022	$ 667
Total costs and other deductions	**810**	947	713
Net income attributable to CTC	**(124)**	120	(39)

	At December 31	
	2009	2008
Current assets	**$ 377**	$ 482
Other assets	**173**	172
Current liabilities	**115**	98
Other liabilities	**90**	88
Total CTC net equity	**345**	468

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2009.

Note 7

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 12, on page 41, for a discussion of TCO operations.

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

	Year ended December 31		
	2009	2008	2007
Sales and other operating revenues	**$12,013**	$14,329	$8,919
Costs and other deductions	**6,044**	5,621	3,387
Net income attributable to TCO	**4,178**	6,134	3,952

	At December 31	
	2009	2008
Current assets	**$ 3,190**	$ 2,740
Other assets	**12,022**	12,240
Current liabilities	**2,426**	1,867
Other liabilities	**4,484**	4,759
Total TCO net equity	**8,302**	8,354

Note 8

Lease Commitments

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

	At December 31	
	2009	2008
Upstream	**$ 510**	$ 491
Downstream	**334**	401
All other	**169**	169
Total	**1,013**	1,061
Less: Accumulated amortization	**585**	522
Net capitalized leased assets	**$ 428**	$ 539

Rental expenses incurred for operating leases during 2009, 2008 and 2007 were as follows:

	Year ended December 31		
	2009	2008	2007
Minimum rentals	**$2,179**	$2,984	$2,419
Contingent rentals	**7**	6	6
Total	**2,186**	2,990	2,425
Less: Sublease rental income	**41**	41	30
Net rental expense	**$2,145**	$2,949	$2,395

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, 2009, 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: 2010	568	90
2011	438	81
2012	406	87
2013	372	60
2014	347	44
Thereafter	1,233	137
Total	$ 3,364	$ 499
Less: Amounts representing interest and executory costs		(104)
Net present values		395
Less: Capital lease obligations included in short-term debt		(94)
Long-term capital lease obligations		$ 301

Note 9

Fair Value Measurements

Accounting standards for fair-value measurement (ASC 820) establish a framework for measuring fair value and stipulate disclosures about fair-value measurements. The standards apply to recurring and nonrecurring financial and nonfinancial assets and liabilities that require or permit fair-value measurements. ASC 820 became effective for Chevron on January 1, 2008, for all financial assets and liabilities and recurring nonfinancial assets and liabilities. On January 1, 2009, the standard became effective for nonrecurring nonfinancial assets and liabilities. Among the required disclosures is the fair-value hierarchy of inputs the company uses to value an asset or a liability. The three levels of the fair-value hierarchy are described as follows:

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

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

Level 3: Unobservable inputs. The company does not use Level 3 inputs for any of its recurring fair-value measurements. Level 3 inputs may be required for the determination of fair value associated with certain nonrecurring measurements of nonfinancial assets and liabilities. In 2009, the company used Level 3 inputs to determine the fair value of certain nonrecurring nonfinancial assets.

The fair-value hierarchy for recurring assets and liabilities measured at fair value at December 31, 2009, and December 31, 2008, is as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31 **2009**	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	At December 31 2008	Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Marketable Securities	**$ 106**	**$ 106**	**$ –**	**$ –**	$ 213	$ 213	$ –	$ –
Derivatives	**127**	**14**	**113**	**–**	805	529	276	–
Total Recurring Assets at Fair Value	**$ 233**	**$ 120**	**$ 113**	**$ –**	$ 1,018	$ 742	$ 276	$ –
Derivatives	**$ 101**	**$ 20**	**$ 81**	**$ –**	$ 516	$ 98	$ 418	$ –
Total Recurring Liabilities at Fair Value	**$ 101**	**$ 20**	**$ 81**	**$ –**	$ 516	$ 98	$ 418	$ –

Marketable Securities The company calculates fair value for its marketable securities based on quoted market prices for identical assets and liabilities. The fair values reflect the cash that would have been received if the instruments were sold at December 31, 2009. Marketable securities had average maturities of less than one year.

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

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

Derivatives classified as Level 2 include swaps, options, and forward contracts principally with financial institutions and other oil and gas companies, the fair values for which are obtained from third-party broker quotes, industry pricing services and exchanges. The company obtains multiple sources of pricing information for the Level 2 instruments. Since this pricing information is generated from observable market data, it has historically been very consistent. The company does not materially adjust this information. The company incorporates internal review, evaluation and assessment procedures, including a comparison of Level 2 fair values derived from the company's internally developed forward curves (on a sample basis) with the pricing information to document reasonable, logical and supportable fair-value determinations and proper level of classification.

Impairments of "Properties, plant and equipment" During 2009 and in accordance with the accounting standard for the impairment or disposal of long-lived assets (ASC 360), long-lived assets "held and used" with a carrying amount of $949 were written down to a fair value of $490, resulting in a before-tax loss of $459. The fair values were determined from internal cash-flow models, using discount rates consistent with those used by the company to evaluate cash flows of other assets of a similar nature. Long-lived assets "held for sale" with a carrying amount of $160 were written down to a fair value of $68, resulting in a before-tax loss of $92. The fair values were determined based on bids received from prospective buyers.

The fair-value hierarchy for nonrecurring assets and liabilities measured at fair value during 2009 is presented in the following table.

Assets and Liabilities Measured at Fair Value on a Non-recurring Basis

	Year Ended December 31 2009	Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Loss (Before Tax) Year Ended December 31 2009
Properties, plant and equipment, net (held and used)	**$ 490**	$ –	$ –	$ 490	$ 459
Properties, plant and equipment, net (held for sale)	**68**	–	68	–	92
Total Nonrecurring Assets at Fair Value	**$ 558**	$ –	$ 68	$ 490	$ 551

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents in U.S. and non-U.S. portfolios. The instruments held are primarily time deposits and money market funds. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end. Cash equivalents had carrying/fair values of $6,396 and $7,058 at December 31, 2009 and 2008, respectively, and average maturities under 90 days. The balance at December 31, 2009, includes $123 of investments for restricted funds related to an international upstream development project and Pascagoula Refinery projects, which are included in “Deferred charges and other assets” on the Consolidated Balance Sheet. Long-term debt of $5,705 and $1,221 had estimated fair values of $6,229 and $1,414 at December 31, 2009 and 2008, respectively.

Fair values of other financial instruments at the end of 2009 and 2008 were not material.

Note 10

Financial and Derivative Instruments

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

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

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

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

Derivative instruments measured at fair value at December 31, 2009, and December 31, 2008, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are as follows:

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

		Asset Derivatives – Fair Value			Liability Derivatives – Fair Value	
Type of Derivative Contract	Balance Sheet Classification	At December 31 **2009**	At December 31 2008	Balance Sheet Classification	At December 31 **2009**	At December 31 2008
Foreign Exchange	Accounts and notes receivable, net	**$ –**	$ 11	Accrued liabilities	**$ –**	$ 89
Commodity	Accounts and notes receivable, net	**99**	764	Accounts payable	**73**	344
Commodity	Long-term receivables, net	**28**	30	Deferred credits and other noncurrent obligations	**28**	83
		$ 127	$ 805		**$ 101**	$ 516

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

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

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

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

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 result, the company believes concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, requiring Letters of Credit is a principal method used to support sales to customers.

Note 11

Operating Segments and Geographic Data

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. The investments are grouped into two business segments, Upstream and Downstream, representing the company's "reportable segments" and "operating segments" as defined in accounting standards for segment reporting (ASC 280). Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation, regasification, storage and marketing associated with natural gas; transporting crude oil by major international oil-export pipelines; and a gas-to-liquids project. Downstream operations consist primarily of refining of crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and additives for fuels and lubricant oils. All Other activities of the company include mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, energy services, alternative fuels and technology, and the company's interest in Dynegy (through May 2007, when Chevron sold its interest).

The segments are separately managed for investment purposes under a structure that includes "segment managers" who report to the company's "chief operating decision maker" (CODM) (terms as defined in ASC 280). The CODM is the company's Executive Committee, 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 accounting standards for segment reporting (ASC 280), that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and to assess their performance; and (c) for which discrete financial information is available.

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

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

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

	Year ended December 31		
	2009	2008	2007
Segment Earnings			
Upstream			
United States	**$ 2,262**	$ 7,147	$ 4,541
International	**8,670**	15,022	10,577
Total Upstream	**10,932**	22,169	15,118
Downstream			
United States	**(121)**	1,369	1,209
International	**594**	1,783	2,387
Total Downstream	473	3,152	3,596
Total Segment Earnings	**11,405**	25,321	18,714
All Other			
Interest expense	**(22)**	–	(107)
Interest income	**46**	192	385
Other	**(946)**	(1,582)	(304)
Net Income Attributable to Chevron Corporation	**$ 10,483**	$ 23,931	$ 18,688

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2009 and 2008 are as follows:

	At December 31	
	2009	2008
Upstream		
United States	**$ 25,478**	$ 26,645
International	**81,209**	77,176
Goodwill	**4,618**	4,619
Total Upstream	**111,305**	108,440
Downstream		
United States	**20,317**	17,830
International	**19,618**	20,012
Total Downstream	**39,935**	37,842
Total Segment Assets	**151,240**	146,282
All Other*		
United States	**7,125**	8,984
International	**6,256**	5,899
Total All Other	**13,381**	14,883
Total Assets – United States	**52,920**	53,459
Total Assets – International	**107,083**	103,087
Goodwill	**4,618**	4,619
Total Assets	**$ 164,621**	$ 161,165

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

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2009, 2008 and 2007, are presented in the table on the following page. Products are transferred between operating segments at internal product values that approximate market prices.

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

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Note 11 Operating Segments and Geographic Data - Continued

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 2009, 2008 and 2007.

	Year ended December 31		
	2009	2008	2007
Upstream			
United States	**$ 9,225**	$ 23,566	$ 18,783
Intersegment	**10,297**	15,162	11,648
Total United States	**19,522**	38,728	30,431
International	**13,463**	19,531	15,292
Intersegment	**18,477**	24,205	19,647
Total International	**31,940**	43,736	34,939
Total Upstream	**51,462**	82,464	65,370
Downstream			
United States	**58,056**	87,759	70,838
Excise and similar taxes	**4,573**	4,748	4,993
Intersegment	**98**	242	345
Total United States	**62,727**	92,749	76,176
International	**77,845**	123,389	98,242
Excise and similar taxes	**3,536**	5,098	5,128
Intersegment	**87**	80	31
Total International	**81,468**	128,567	103,401
Total Downstream	**144,195**	221,316	179,577
All Other			
United States	**665**	815	757
Intersegment	**964**	917	760
Total United States	**1,629**	1,732	1,517
International	**39**	52	58
Intersegment	**33**	33	31
Total International	**72**	85	89
Total All Other	**1,701**	1,817	1,606
Segment Sales and Other Operating Revenues			
United States	**83,878**	133,209	108,124
International	**113,480**	172,388	138,429
Total Segment Sales and Other Operating Revenues	**197,358**	305,597	246,553
Elimination of intersegment sales	**(29,956)**	(40,639)	(32,462)
Total Sales and Other Operating Revenues	**$167,402**	$264,958	$214,091

Segment Income Taxes Segment income tax expense for the years 2009, 2008 and 2007 is as follows:

	Year ended December 31		
	2009	2008	2007
Upstream			
United States	**$ 1,251**	$ 3,705	$ 2,548
International	**7,451**	15,122	11,321
Total Upstream	**8,702**	18,827	13,869
Downstream			
United States	**(83)**	780	519
International	**463**	871	422
Total Downstream	**380**	1,651	941
All Other	**(1,117)**	(1,452)	(1,331)
Total Income Tax Expense	**$ 7,965**	$19,026	$13,479

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page 41. Information related to properties, plant and equipment by segment is contained in Note 13, on page 43.

Note 12

Investments and Advances

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, is shown in the 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		
	2009	2008	**2009**	2008	2007
Upstream					
Tengizchevroil	**$ 5,938**	$ 6,290	**$2,216**	$3,220	$2,135
Petropiar/Hamaca	**1,139**	1,130	**122**	317	327
Caspian Pipeline Consortium	**852**	749	**105**	103	102
Petroboscan	**832**	816	**171**	244	185
Angola LNG Limited	**1,853**	1,191	**(12)**	(8)	21
Other	**1,947**	1,893	**287**	424	399
Total Upstream	**12,561**	12,069	**2,889**	4,300	3,169
Downstream					
GS Caltex Corporation	**2,406**	2,601	**(191)**	444	217
Chevron Phillips Chemical Company LLC	**2,327**	2,037	**328**	158	380
Star Petroleum Refining Company Ltd.	**873**	877	**(4)**	22	157
Caltex Australia Ltd.	**740**	723	**11**	250	129
Colonial Pipeline Company	**514**	536	**51**	32	39
Other	**540**	521	**149**	140	129
Total Downstream	**7,400**	7,295	**344**	1,046	1,051
All Other					
Other	**507**	567	**83**	20	(76)
Total equity method	**$20,468**	$19,931	**$3,316**	$5,366	$4,144
Other at or below cost	**690**	989			
Total investments and advances	**$21,158**	$20,920			
Total United States	**$ 4,195**	$ 4,002	**$ 511**	$ 307	$ 478
Total International	**$16,963**	$16,918	**$2,805**	$5,059	$3,666

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

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude-oil fields in Kazakhstan over a 40-year period. At December 31, 2009, the company's carrying value of its investment in TCO was about $200 higher than the amount of underlying equity in TCO's net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO's net assets. See Note 7, on page 34, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company formed in 2008 to operate the Hamaca heavy-oil production and upgrading project. The project, located in Venezuela's Orinoco Belt, has a 25-year contract term. Prior to the formation of Petropiar, Chevron had a 30 percent interest in the Hamaca project. At December 31, 2009, the company's carrying value of its investment in Petropiar was approximately $195 less than the amount of underlying equity in Petropiar's net assets. The difference represents the excess of Chevron's underlying equity in Petropiar's net assets over the net book value of the assets contributed to the venture.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, which provides the critical export route for crude oil from both TCO and Karachaganak.

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, 2009, the company's carrying value of its investment in Petroboscan was approximately $275 higher than the amount of underlying equity in Petroboscan's net assets. The difference reflects the excess of the net book value of the assets contributed by Chevron over its underlying equity in Petroboscan's net assets.

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

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

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

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

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Ltd. (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2009, the fair value of Chevron's share of CAL common stock was approximately $1,120.

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, 2009, the company's carrying value of its investment in Colonial Pipeline was approximately $550 higher than the amount of underlying equity in Colonial Pipeline net assets. This difference primarily relates to purchase price adjustments from the acquisition of Unocal Corporation.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $10,391, $15,390 and $11,555 with affiliated companies for 2009, 2008 and 2007, respectively. "Purchased crude oil and products" includes
$4,631, $6,850 and $5,464 with affiliated companies for 2009, 2008 and 2007, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,125 and $701 due from affiliated companies at December 31, 2009 and 2008, respectively. "Accounts payable" includes $345 and $289 due to affiliated companies at December 31, 2009 and 2008, respectively.

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

	Affiliates			Chevron Share		
Year ended December 31	**2009**	2008	2007	**2009**	2008	2007
Total revenues	**$ 81,995**	$ 112,707	$ 94,864	**$ 39,280**	$ 54,055	$ 46,579
Income before income tax expense	**11,083**	17,500	12,510	**4,511**	7,532	5,836
Net income attributable to affiliates	**8,261**	12,705	9,743	**3,285**	5,524	4,550
At December 31						
Current assets	**$ 27,111**	$ 25,194	$ 26,360	**$ 11,009**	$ 10,804	$ 11,914
Noncurrent assets	**55,363**	51,878	48,440	**21,361**	20,129	19,045
Current liabilities	**17,450**	17,727	19,033	**7,833**	7,474	9,009
Noncurrent liabilities	**21,531**	21,049	22,757	**5,106**	4,533	3,745
Total affiliates' net equity	**$ 43,493**	$ 38,296	$ 33,010	**$ 19,431**	$ 18,926	$ 18,205

Note 13

Properties, Plant and Equipment[1]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expense[3]		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Upstream												
United States	**$ 58,328**	$ 54,878	$ 51,789	**$ 22,273**	$ 22,701	$ 20,263	**$ 3,518**	$ 5,395	$ 5,756	**$ 3,992**	$ 2,704	$ 2,718
International	**96,557**	86,676	72,138	**57,450**	53,371	44,017	**10,803**	14,997	10,514	**6,669**	5,461	4,623
Total Upstream	**154,885**	141,554	123,927	**79,723**	76,072	64,280	**14,321**	20,392	16,270	**10,661**	8,165	7,341
Downstream												
United States	**18,962**	17,397	15,687	**10,032**	8,908	7,580	**1,874**	2,061	1,523	**666**	627	510
International	**9,852**	10,021	10,556	**4,154**	4,266	4,557	**456**	537	570	**454**	482	641
Total Downstream	**28,814**	27,418	26,243	**14,186**	13,174	12,137	**2,330**	2,598	2,093	**1,120**	1,109	1,151
All Other[4]												
United States	**4,569**	4,310	3,873	**2,548**	2,523	2,179	**354**	598	680	**325**	250	215
International	**20**	17	41	**11**	11	14	**3**	5	5	**4**	4	1
Total All Other	**4,589**	4,327	3,914	**2,559**	2,534	2,193	**357**	603	685	**329**	254	216
Total United States	**81,859**	76,585	71,349	**34,853**	34,132	30,022	**5,746**	8,054	7,959	**4,983**	3,581	3,443
Total International	**106,429**	96,714	82,735	**61,615**	57,648	48,588	**11,262**	15,539	11,089	**7,127**	5,947	5,265
Total	**$ 188,288**	$ 173,299	$ 154,084	**$ 96,468**	$ 91,780	$ 78,610	**$ 17,008**	$ 23,593	$ 19,048	**$ 12,110**	$ 9,528	$ 8,708

[1] Other than the United States and Nigeria, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2009 and 2008. Only the United States had more than 10 percent in 2007. Nigeria had net PP&E of $12,463 and $10,730 for 2009 and 2008, respectively.

[2] Net of dry hole expense related to prior years' expenditures of $84, $55 and $89 in 2009, 2008 and 2007, respectively.

[3] Depreciation expense includes accretion expense of $463, $430 and $399 in 2009, 2008 and 2007, respectively.

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

Note 14

Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to 50 pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to pending lawsuits and claims is not determinable, but could be material to net income in any one period. The company no longer uses MTBE in the manufacture of gasoline in the United States.

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

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

In April 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess $8,000, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer's report also asserted that an additional $8,300 could be assessed against Chevron for unjust enrichment. The engineer's report is not binding on the court. Chevron also believes that the engineer's work was performed and his report prepared in a manner contrary to law and in violation of the court's orders. Chevron submitted a rebuttal to the report in which it asked the court to strike the report in its entirety. In November 2008, the engineer revised the report and, without additional evidence, recommended an increase in the financial compensation for purported damages to a total of $18,900 and an increase in the assessment for purported unjust enrichment to a total of $8,400. Chevron submitted a rebuttal to the revised report, which the court dismissed. In September 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case petitioned to be recused. In late September 2009, the judge was recused, and in October 2009, the full chamber of the provincial court affirmed the recusal, resulting in the appointment of a new judge. Chevron filed motions to annul all of the rulings made by the prior judge, but the new judge denied these motions. The court has completed most of the procedural aspects of the case and could render a judgment at any time. Chevron will continue a vigorous defense of any attempted imposition of liability.

In the event of an adverse judgment, Chevron would expect to pursue its appeals and vigorously defend against enforcement of any such judgment; therefore, the ultimate outcome – and any financial effect on Chevron – remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this case. Due to the defects associated with the engineer's report, management does not believe the report has any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

Note 15
Taxes
Income Taxes

	Year ended December 31		
	2009	2008	2007
Taxes on income			
U.S. Federal			
Current	**$ 128**	$ 2,879	$ 1,446
Deferred	**(147)**	274	225
State and local			
Current	**216**	528	356
Deferred	**14**	141	(18)
Total United States	**211**	3,822	2,009
International			
Current	**7,154**	15,021	11,416
Deferred	**600**	183	54
Total International	**7,754**	15,204	11,470
Total taxes on income	**$7,965**	$19,026	$13,479

In 2009, before-tax income for U.S. operations, including related corporate and other charges, was $1,310, compared with before-tax income of $10,765 and $7,886 in 2008 and 2007, respectively. For international operations, before-tax income was $17,218, $32,292 and $24,388 in 2009, 2008 and 2007, respectively. U.S. federal income tax expense was reduced by $204, $198 and $132 in 2009, 2008 and 2007, respectively, for business tax credits.

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

	Year ended December 31		
	2009	2008	2007
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	**10.4**	10.1	8.2
State and local taxes on income, net of U.S. federal income tax benefit	**0.9**	1.0	0.8
Prior-year tax adjustments	**(0.3)**	(0.1)	0.3
Tax credits	**(1.1)**	(0.5)	(0.4)
Effects of enacted changes in tax laws	**0.1**	(0.6)	(0.3)
Other	**(2.0)**	(0.7)	(1.8)
Effective tax rate	**43.0%**	44.2%	41.8%

The company's effective tax rate decreased from 44.2 percent in 2008 to 43.0 percent in 2009. The rate was lower in 2009 mainly due to the effect of deferred tax benefits and relatively low tax rates on asset sales, both related to an international upstream project. In addition, a greater proportion of before-tax income was earned in 2009 by equity affiliates than in 2008. (Equity-affiliate income is reported as a single amount on an after-tax basis on the Consolidated Statement of Income.) Partially offsetting these items was the effect of a greater proportion of income earned in 2009 in tax jurisdictions with higher tax rates.

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	
	2009	2008
Deferred tax liabilities		
Properties, plant and equipment	**$ 18,545**	$ 18,271
Investments and other	**2,350**	2,225
Total deferred tax liabilities	**20,895**	20,496
Deferred tax assets		
Foreign tax credits	**(5,387)**	(4,784)
Abandonment/environmental reserves	**(4,424)**	(4,338)
Employee benefits	**(3,499)**	(3,488)
Deferred credits	**(3,469)**	(3,933)
Tax loss carryforwards	**(819)**	(1,139)
Other accrued liabilities	**(553)**	(445)
Inventory	**(431)**	(260)
Miscellaneous	**(1,681)**	(1,732)
Total deferred tax assets	**(20,263)**	(20,119)
Deferred tax assets valuation allowance	**7,921**	7,535
Total deferred taxes, net	**$ 8,553**	$ 7,912

Deferred tax liabilities at the end of 2009 increased by approximately $400 from year-end 2008. The increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets were essentially unchanged in 2009. Increases related to additional foreign tax credits arising from earnings in high-tax-rate international jurisdictions (which were substantially offset by valuation allowances) and to inventory-related temporary differences. These effects were offset by reductions in deferred credits and tax loss carryforwards primarily resulting from the usage of tax benefits in international tax jurisdictions.

The overall valuation allowance relates to deferred tax assets for foreign tax credit carryforwards, tax loss carryforwards and temporary differences. It reduces the deferred tax assets to amounts that are, in management's assessment, more likely than not to be realized. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2010 through 2036. Foreign tax credit carryforwards of $5,387 will expire between 2010 and 2019.

At December 31, 2009 and 2008, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2009	2008
Prepaid expenses and other current assets	**$ (1,825)**	$ (1,130)
Deferred charges and other assets	**(1,268)**	(2,686)
Federal and other taxes on income	**125**	189
Noncurrent deferred income taxes	**11,521**	11,539
Total deferred income taxes, net	**$ 8,553**	$ 7,912

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 $20,458 at December 31, 2009. 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 2009, deferred income taxes were recorded for the undistributed earnings of certain international operations for which the company no longer intends to indefinitely reinvest the earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

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

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

	2009	2008	2007
Balance at January 1	**$2,696**	$2,199	$2,296
Foreign currency effects	**(1)**	(1)	19
Additions based on tax positions taken in current year	**459**	522	418
Reductions based on tax positions taken in current year	**–**	(17)	–
Additions/reductions resulting from current-year asset acquisitions/sales	**–**	175	–
Additions for tax positions taken in prior years	**533**	337	120
Reductions for tax positions taken in prior years	**(182)**	(246)	(225)
Settlements with taxing authorities in current year	**(300)**	(215)	(255)
Reductions as a result of a lapse of the applicable statute of limitations	**(10)**	(58)	–
Reductions due to tax positions previously expected to be taken but subsequently not taken on prior-year tax returns	**–**	–	(174)
Balance at December 31	**$3,195**	$2,696	$2,199

Although unrecognized tax benefits for individual tax positions may increase or decrease during 2010, the company believes that no change will be individually significant during 2010. Approximately 90 percent of the $3,195 of unrecognized tax benefits at December 31, 2009, would have an impact on the effective 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, 2009. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2005, Nigeria – 1994, Angola – 2001 and Saudi Arabia – 2003.

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, 2009, accruals of $232 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $276 as of year-end 2008. Income tax (benefit) expense associated with interest and penalties was $(20), $79 and $70 in 2009, 2008 and 2007, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2009	2008	2007
United States			
Excise and similar taxes on products and merchandise	**$ 4,573**	$ 4,748	$ 4,992
Import duties and other levies	**(4)**	1	12
Property and other miscellaneous taxes	**584**	588	491
Payroll taxes	**223**	204	185
Taxes on production	**135**	431	288
Total United States	**5,511**	5,972	5,968
International			
Excise and similar taxes on products and merchandise	**3,536**	5,098	5,129
Import duties and other levies	**6,550**	8,368	10,404
Property and other miscellaneous taxes	**1,740**	1,557	528
Payroll taxes	**134**	106	89
Taxes on production	**120**	202	148
Total International	**12,080**	15,331	16,298
Total taxes other than on income	**$17,591**	$21,303	$22,266

Note 16
Short-Term Debt

	At December 31	
	2009	2008
Commercial paper*	**$ 2,499**	$ 5,742
Notes payable to banks and others with originating terms of one year or less	**213**	149
Current maturities of long-term debt	**66**	429
Current maturities of long-term capital leases	**76**	78
Redeemable long-term obligations		
Long-term debt	**1,702**	1,351
Capital leases	**18**	19
Subtotal	**4,574**	7,768
Reclassified to long-term debt	**(4,190)**	(4,950)
Total short-term debt	**$ 384**	$ 2,818

* Weighted-average interest rates at December 31, 2009 and 2008, were 0.08 percent and 0.67 percent, respectively.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders within one year following the balance sheet date. In 2009, $350 of tax-exempt Gulf Opportunity Zone bonds related to projects at the Pascagoula Refinery were issued.

The company periodically enters into interest rate swaps on a portion of its short-term debt. At December 31, 2009, the company had no interest rate swaps on short-term debt. See Note 10, beginning on page 37, for information concerning the company's debt-related derivative activities.

At December 31, 2009, the company had $5,100 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 on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2009 or at year-end.

At December 31, 2009 and 2008, the company classified $4,190 and $4,950, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2010, 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, 2009, was $9,829. The company's long-term debt outstanding at year-end 2009 and 2008 was as follows:

	At December 31	
	2009	2008
3.95% notes due 2014	**$1,997**	$ –
3.45% notes due 2012	**1,500**	–
4.95% notes due 2019	**1,500**	–
5.5% notes due 2009	**–**	400
8.625% debentures due 2032	**147**	147
7.327% amortizing notes due 2014[1]	**109**	194
8.625% debentures due 2031	**107**	108
7.5% debentures due 2043	**83**	85
8% debentures due 2032	**74**	74
9.75% debentures due 2020	**56**	56
8.875% debentures due 2021	**40**	40
8.625% debentures due 2010	**30**	30
Medium-term notes, maturing from 2021 to 2038 (5.97%)[2]	**38**	38
Fixed interest rate notes, maturing 2011 (9.378%)[2]	**19**	21
Other foreign currency obligations	**–**	13
Other long-term debt (6.69%)[2]	**5**	15
Total including debt due within one year	**5,705**	1,221
Debt due within one year	**(66)**	(429)
Reclassified from short-term debt	**4,190**	4,950
Total long-term debt	**$9,829**	$5,742

1 Guarantee of ESOP debt.
2 Weighted-average interest rate at December 31, 2009.

Long-term debt of $5,705 matures as follows: 2010 – $66; 2011 – $33; 2012 – $1,520; 2013 – $21; 2014 – $2,020; and after 2014 – $2,045.

In 2009, $5,000 of public bonds was issued, and $400 of Texaco Capital Inc. bonds matured. In 2008, debt totaling $822 matured, including $749 of Chevron Canada Funding Company notes.

Note 18

New Accounting Standards

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162 (FAS 168) In June 2009, the FASB issued FAS 168, which became effective for the company in the quarter ending September 30, 2009. This standard established the FASB Accounting Standards Codification (ASC) system as the single authoritative source of U.S. generally accepted accounting principles (GAAP) and superseded existing literature of the FASB, Emerging Issues Task Force, American Institute of CPAs and other sources. The ASC did not change GAAP, but organized the literature into about 90 accounting Topics. Adoption of the ASC did not affect the company's accounting.

Employer's Disclosures About Postretirement Benefit Plan Assets (FSP FAS 132(R)-1) In December 2008, the FASB issued FSP FAS 132(R)-1, which was subsequently codified into ASC 715, *Compensation – Retirement Benefits*, and became effective with the company's reporting at December 31, 2009. This standard amended and expanded the disclosure requirements for the plan assets of defined benefit pension and other postretirement plans. Refer to information beginning on page 50 in Note 21, Employee Benefits, for these disclosures.

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

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

Extractive Industries – Oil and Gas (ASC 932), Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03) In January 2010, the FASB issued ASU 2010-03, which became effective for the company on December 31, 2009. The standard amends certain sections of ASC 932, *Extractive Industries – Oil and Gas*, to align them with the requirements in the Securities and Exchange Commission's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the final rule). The final rule was issued on December 31, 2008. Refer to Table V – Reserve Quantity Information, beginning on page FS-69 in our 2009 Form 10-K, for additional information on the final rule and the impact of adoption.

Note 19

Accounting for Suspended Exploratory Wells

Accounting standards for the costs of exploratory wells (ASC 932) provide that exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the 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. The accounting standards provide a number of indicators that can assist an entity in demonstrating that sufficient progress is being made in assessing the reserves and economic viability of the project.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2009:

	2009	2008	2007
Beginning balance at January 1	**$ 2,118**	$ 1,660	$ 1,239
Additions to capitalized exploratory well costs pending the determination of proved reserves	**663**	643	486
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(174)**	(49)	(23)
Capitalized exploratory well costs charged to expense	**(172)**	(136)	(42)
Ending balance at December 31	**$ 2,435**	$ 2,118	$ 1,660

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

	At December 31		
	2009	2008	2007
Exploratory well costs capitalized for a period of one year or less	**$ 564**	$ 559	$ 449
Exploratory well costs capitalized for a period greater than one year	**1,871**	1,559	1,211
Balance at December 31	**$ 2,435**	$ 2,118	$ 1,660
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**46**	50	54

* Certain projects have multiple wells or fields or both.

Of the $1,871 of exploratory well costs capitalized for more than one year at December 31, 2009, $1,143 (28 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The $728 balance is related to 18 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.

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The projects for the $728 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $330 (one project) – negotiation of crude-oil and natural-gas transportation contracts and construction agreements; (b) $107 (two projects) – discussion with possible natural-gas purchasers ongoing; (c) $73 (two projects) – continued unitization efforts on adjacent discoveries that span international boundaries while planning on an LNG facility has commenced; (d) $49 (one project) – progression of development concept selection; (e) $47 (one project) – subsurface and facilities engineering studies concluding with front-end engineering and design expected to begin in early 2010; (f) $34 (one project) – reviewing development alternatives; $88 – miscellaneous activities for 10 projects with smaller amounts suspended. While progress was being made on all 46 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 $1,871 of suspended well costs capitalized for a period greater than one year as of December 31, 2009, represents 149 exploratory wells in 46 projects. The tables below contain the aging of these costs on a well and project basis:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1992	$ 8	3
1997–1998	15	3
1999–2003	271	42
2004–2008	1,577	101
Total	$ 1,871	149

Aging based on drilling completion date of last suspended well in project:	Amount	Number of projects
1992	$ 8	1
1999	8	1
2003–2004	242	5
2005–2009	1,613	39
Total	$ 1,871	46

Note 20

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2009, 2008 and 2007 was $182 ($119 after tax), $168 ($109 after tax) and $146 ($95 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was $170 ($110 after tax), $132 ($86 after tax) and $205 ($133 after tax) for 2009, 2008 and 2007, respectively. No significant stock-based compensation cost was capitalized at December 31, 2009 and 2008.

Cash received in payment for option exercises under all share-based payment arrangements for 2009, 2008 and 2007 was $147, $404 and $445, respectively. Actual tax benefits realized for the tax deductions from option exercises were $25, $103 and $94 for 2009, 2008 and 2007, respectively.

Cash paid to settle performance units and stock appreciation rights was $89, $136 and $88 for 2009, 2008 and 2007, respectively.

Chevron Long-Term Incentive Plan (LTIP) Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and nonstock grants. From April 2004 through January 2014, no more than 160 million shares may be issued under the LTIP, and no more than 64 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient.

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

Unocal Share-Based Plans (Unocal Plans) When Chevron acquired Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights. These awards retained the same provisions as the original Unocal Plans. If not exercised, these awards will expire between early 2010 and early 2015.

The fair market values of stock options and stock appreciation rights granted in 2009, 2008 and 2007 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2009	2008	2007
Stock Options			
Expected term in years[1]	**6.0**	6.1	6.3
Volatility[2]	**30.2%**	22.0%	22.0%
Risk-free interest rate based on zero coupon U.S. treasury note	**2.1%**	3.0%	4.5%
Dividend yield	**3.2%**	2.7%	3.2%
Weighted-average fair value per option granted	**$15.36**	$15.97	$15.27
Restored Options			
Expected term in years[1]	**1.2**	1.2	1.6
Volatility[2]	**45.0%**	23.1%	21.2%
Risk-free interest rate based on zero coupon U.S. treasury note	**1.1%**	1.9%	4.5%
Dividend yield	**3.5%**	2.7%	3.2%
Weighted-average fair value per option granted	**$12.38**	$10.01	$ 8.61

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

A summary of option activity during 2009 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2009	59,013	$ 61.36		
Granted	14,709	$ 69.69		
Exercised	(3,418)	$ 45.75		
Restored	1	$ 70.40		
Forfeited	(842)	$ 76.02		
Outstanding at December 31, 2009	69,463	$ 63.70	6.4 yrs	$ 1,019
Exercisable at December 31, 2009	44,120	$ 57.34	5.1 yrs	$ 904

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2009, 2008 and 2007 was $91, $433 and $423, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2009, there was $233 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 1.8 years.

At January 1, 2009, the number of LTIP performance units outstanding was equivalent to 2,400,555 shares. During 2009, 992,800 units were granted, 668,953 units vested with cash proceeds distributed to recipients and 45,294 units were forfeited. At December 31, 2009, units outstanding were 2,679,108, and the fair value of the liability recorded for these instruments was $233. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Texaco and Unocal programs totaled approximately 1.5 million equivalent shares as of December 31, 2009. A liability of $45 was recorded for these awards.

In March 2009, Chevron granted all eligible LTIP employees restricted stock units in lieu of annual cash bonus. The expense associated with these special restricted stock units was recognized at the time of the grants. A total of 453,965 units were granted at $69.70 per unit at the time of the grant. Total fair value of the special restricted stock units was $32 as of December 31, 2009. All of the special restricted stock units will be payable in November 2010.

Note 21

Employee Benefit Plans

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

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

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

The funded status of the company's pension and other postretirement benefit plans for 2009 and 2008 is on the following page:

Note 21 Employee Benefit Plans - Continued

	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Pension Benefits 2008 U.S.	Pension Benefits 2008 Int'l.	Other Benefits 2009	Other Benefits 2008
Change in Benefit Obligation						
Benefit obligation at January 1	$ 8,127	$ 3,891	$ 8,395	$ 4,633	$ 2,931	$ 2,939
Service cost	266	128	250	132	43	44
Interest cost	481	292	499	292	180	178
Plan participants' contributions	–	7	–	9	145	152
Plan amendments	1	10	–	32	20	–
Curtailments	–	–	–	–	(5)	–
Actuarial loss (gain)	1,391	299	(62)	(104)	56	(14)
Foreign currency exchange rate changes	–	333	–	(858)	27	(28)
Benefits paid	(602)	(245)	(955)	(246)	(332)	(340)
Special termination benefits	–	–	–	1	–	–
Benefit obligation at December 31	9,664	4,715	8,127	3,891	3,065	2,931
Change in Plan Assets						
Fair value of plan assets at January 1	5,448	2,600	7,918	3,892	–	–
Actual return on plan assets	964	402	(2,092)	(655)	–	–
Foreign currency exchange rate changes	–	226	–	(662)	–	–
Employer contributions	1,494	245	577	262	187	188
Plan participants' contributions	–	7	–	9	145	152
Benefits paid	(602)	(245)	(955)	(246)	(332)	(340)
Fair value of plan assets at December 31	7,304	3,235	5,448	2,600	–	–
Funded Status at December 31	$ (2,360)	$ (1,480)	$ (2,679)	$ (1,291)	$ (3,065)	$ (2,931)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2009 and 2008, include:

	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Pension Benefits 2008 U.S.	Pension Benefits 2008 Int'l.	Other Benefits 2009	Other Benefits 2008
Deferred charges and other assets	$ 6	$ 37	$ 6	$ 31	$ –	$ –
Accrued liabilities	(66)	(67)	(72)	(61)	(208)	(209)
Reserves for employee benefit plans	(2,300)	(1,450)	(2,613)	(1,261)	(2,857)	(2,722)
Net amount recognized at December 31	$ (2,360)	$ (1,480)	$ (2,679)	$ (1,291)	$ (3,065)	$ (2,931)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were $6,454 and $5,831 at the end of 2009 and 2008, respectively. These amounts consisted of:

	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Pension Benefits 2008 U.S.	Pension Benefits 2008 Int'l.	Other Benefits 2009	Other Benefits 2008
Net actuarial loss	$ 4,181	$ 1,889	$ 3,797	$ 1,804	$ 465	$ 410
Prior-service (credit) costs	(60)	201	(68)	211	(222)	(323)
Total recognized at December 31	$ 4,121	$ 2,090	$ 3,729	$ 2,015	$ 243	$ 87

The accumulated benefit obligations for all U.S. and international pension plans were $8,707 and $4,029, respectively, at December 31, 2009, and $7,376 and $3,273, respectively, at December 31, 2008.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2009 and 2008, was:

	Pension Benefits 2009 U.S.	Pension Benefits 2009 Int'l.	Pension Benefits 2008 U.S.	Pension Benefits 2008 Int'l.
Projected benefit obligations	$9,658	$3,550	$8,121	$2,906
Accumulated benefit obligations	8,702	3,102	7,371	2,539
Fair value of plan assets	7,292	2,116	5,436	1,698

The components of net periodic benefit cost and amounts recognized in other comprehensive income for 2009, 2008 and 2007 are shown in the table below:

	Pension Benefits						Other Benefits		
	2009		2008		2007				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2009**	2008	2007
Net Periodic Benefit Cost									
Service cost	**$ 266**	**$ 128**	$ 250	$ 132	$ 260	$ 125	**$ 43**	$ 44	$ 49
Interest cost	**481**	**292**	499	292	483	255	**180**	178	184
Expected return on plan assets	**(395)**	**(203)**	(593)	(273)	(578)	(266)	**–**	–	–
Amortization of prior-service (credits) costs	**(7)**	**23**	(7)	24	46	17	**(81)**	(81)	(81)
Recognized actuarial losses	**298**	**108**	60	77	128	82	**27**	38	81
Settlement losses	**141**	**1**	306	2	65	–	**–**	–	–
Curtailment losses	**–**	**–**	–	–	–	3	**(5)**	–	–
Special termination benefit recognition	**–**	**–**	–	1	–	–	**–**	–	–
Total net periodic benefit cost	**784**	**349**	515	255	404	216	**164**	179	233
Changes Recognized in Other Comprehensive Income									
Net actuarial loss (gain) during period	**823**	**194**	2,624	646	(160)	31	**82**	(42)	(401)
Amortization of actuarial loss	**(439)**	**(109)**	(366)	(79)	(193)	(82)	**(27)**	(38)	(81)
Prior service cost (credit) during period	**1**	**13**	–	32	(301)	97	**20**	–	–
Amortization of prior-service credits (costs)	**7**	**(23)**	7	(24)	(46)	(20)	**81**	81	81
Total changes recognized in other comprehensive income	**392**	**75**	2,265	575	(700)	26	**156**	1	(401)
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 1,176**	**$ 424**	$ 2,780	$ 830	$ (296)	$ 242	**$ 320**	$ 180	$ (168)

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2009, for the company's U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 11, 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 2010, the company estimates actuarial losses of $318, $102 and $26 will be amortized from "Accumulated other comprehensive loss" for U.S. pension, international pension and OPEB plans, respectively. In addition, the company estimates an additional $220 will be recognized from "Accumulated other comprehensive loss" during 2010 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, 2009, was approximately eight and 12 years for U.S. and international pension plans, respectively, and eight years for other postretirement benefit plans. During 2010, the company estimates prior service (credits) costs of $(7), $27 and $(74) will be amortized from "Accumulated other comprehensive loss" for U.S. pension, international pension and OPEB plans, respectively.

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

	Pension Benefits						Other Benefits		
	2009		2008		2007				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	**2009**	2008	2007
Assumptions used to determine benefit obligations									
Discount rate	**5.3%**	**6.8%**	6.3%	7.5%	6.3%	6.7%	**5.9%**	6.3%	6.3%
Rate of compensation increase	**4.5%**	**6.3%**	4.5%	6.8%	4.5%	6.4%	**N/A**	4.0%	4.5%
Assumptions used to determine net periodic benefit cost									
Discount rate	**6.3%**	**7.5%**	6.3%	6.7%	5.8%	6.0%	**6.3%**	6.3%	5.8%
Expected return on plan assets	**7.8%**	**7.5%**	7.8%	7.4%	7.8%	7.5%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**6.8%**	4.5%	6.4%	4.5%	6.1%	**N/A**	4.5%	4.5%

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

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 69 percent of the company's pension plan assets. At December 31, 2009, 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 year-end is used in calculating the pension expense.

Discount Rate The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2009, the company selected a 5.3 percent discount rate for the U.S. pension plan and 5.8 percent for the U.S. postretirement benefit plan. This rate was based on a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2009. The discount rates at the end of 2008 and 2007 were 6.3 percent for the U.S. pension plan and the OPEB plan.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2009, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 7 percent in 2010 and gradually decline to 5 percent for 2018 and beyond. For this measurement at December 31, 2008, the assumed health care cost-trend rates started with 7 percent in 2009 and gradually declined to 5 percent for 2017 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	$ 10	$ (9)
Effect on postretirement benefit obligation	$ 102	$ (87)

Plan Assets and Investment Strategy Effective December 31, 2009, the company implemented the expanded disclosure requirements for the plan assets of defined benefit pension and OPEB plans (ASC 715) to provide users of financial statements with an understanding of: how investment allocation decisions are made; the major categories of plan assets; the inputs and valuation techniques used to measure the fair value of plan assets; the effect of fair-value measurements using unobservable inputs on changes in plan assets for the period; and significant concentrations of risk within plan assets.

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

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

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

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

The fair value measurements of the company's pension plans for 2009 are below:

	U.S.				Int'l			
	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
Equities								
U.S.[1]	$ 2,115	$ 2,115	$ –	$ –	$ 370	$ 370	$ –	$ –
International	977	977	–	–	492	492	–	–
Collective Trusts/Mutual Funds[2]	1,264	3	1,261	–	789	94	695	–
Fixed Income								
Government	713	149	564	–	506	54	452	–
Corporate	430	–	430	–	371	17	336	18
Mortgage-Backed Securities	149	–	149	–	2	–	–	2
Other Asset Backed	90	–	90	–	19	–	19	–
Collective Trusts/Mutual Funds[2]	326	–	326	–	230	14	216	–
Mixed Funds[3]	8	8	–	–	102	14	88	–
Real Estate[4]	479	–	–	479	131	–	–	131
Cash and Cash Equivalents	743	743	–	–	207	207	–	–
Other[5]	10	(57)	16	51	16	(3)	18	1
Total at December 31, 2009	**$ 7,304**	$ 3,938	$ 2,836	$ 530	**$ 3,235**	$ 1,259	$ 1,824	$ 152

[1] U.S. equities include investments in the company's common stock in the amount of $29 at December 31, 2009.
[2] Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is based on the restriction that advance notification of redemptions, typically two business days, is required.
[3] Mixed funds are composed of funds that invest in both equity and fixed income instruments in order to diversify and lower risk.
[4] The year-end valuations of the U.S. real estate assets are based on internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.
[5] The "Other" asset category includes net payables for securities purchased but not yet settled (Level 1); dividends, interest- and tax-related receivables (Level 2); insurance contracts and investments in private-equity limited partnerships (Level 3).

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

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

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

The company's U.S. and U.K. pension plans comprise 84 percent of the total pension assets. Both the U.S. and U.K. plans have an Investment Committee that regularly meets during the year to review the asset holdings and their returns. To assess the plan's investment performance, long-term asset allocation policy benchmarks have been established.

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

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2009, the company contributed $1,494 and $245 to its U.S. and international pension plans, respectively. In 2010, the company expects contributions to be approximately $600 and $300 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 $208 in 2010, as compared with $187 paid in 2009.

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

	Pension Benefits		Other
	U.S.	Int'l.	Benefits
2010	$ 855	$ 242	$ 208
2011	$ 851	$ 271	$ 213
2012	$ 861	$ 284	$ 217
2013	$ 884	$ 296	$ 222
2014	$ 913	$ 317	$ 229
2015–2019	$ 4,707	$ 1,969	$ 1,197

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

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is described in the section that follows. Total company matching contributions to employee accounts within the ESIP were $257, $231 and $206 in 2009, 2008 and 2007, respectively. This cost was reduced by the value of shares released from the LESOP totaling $184, $40 and $33 in 2009, 2008 and 2007, respectively. The remaining amounts, totaling $73, $191 and $173 in 2009, 2008 and 2007, respectively, represent open market purchases.

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

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

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

Total credits to expense for the LESOP were $3, $1 and $1 in 2009, 2008 and 2007, respectively. The net credit for the respective years was composed of credits to compensation expense of $15, $15 and $17 and charges to interest expense for LESOP debt of $12, $14 and $16.

Of the dividends paid on the LESOP shares, $110, $35 and $8 were used in 2009, 2008 and 2007, respectively, to service LESOP debt. No contributions were required in 2009, 2008 or 2007 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, 2009 and 2008, were as follows:

Thousands	2009	2008
Allocated shares	**21,211**	19,651
Unallocated shares	**3,636**	6,366
Total LESOP shares	**24,847**	26,017

Benefit Plan Trusts Prior to its acquisition by Chevron, Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2009, the trust contained 14.2 million shares of Chevron treasury stock. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The company intends to continue to pay its obligations under the benefit plans. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Prior to its acquisition by Chevron, Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2009 and 2008, trust assets of $57 and $60, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans Effective January 2008, the company established the Chevron Incentive Plan (CIP), a single annual cash bonus plan for eligible employees that links awards to corporate, unit and individual performance in the prior year. This plan replaced other cash bonus programs, which primarily included the Management Incentive Plan (MIP) and the Chevron Success Sharing program. In 2009 and 2008, charges to expense for cash bonuses were $561 and $757, respectively. In 2007, charges to expense for MIP were $184 and charges for other cash bonus programs were $431. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 20, on page 49.

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 44 for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return. The company does not expect settlement of income tax liabilities associated with uncertain tax positions will have a material effect on its results of operations, consolidated financial position or liquidity.

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

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300. Through the end of 2009, 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 had to be asserted by February 2009 for Equilon indemnities and must be asserted no later than February 2012 for Motiva indemnities. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. In February 2009, Shell delivered a letter to the company purporting to preserve unmatured claims for certain Equilon indemnities. The letter itself provides no estimate of the ultimate claim amount. Management does not believe this letter or any other information provides a basis to estimate the amount, if any, of a range of loss or potential range of loss with respect to either the Equilon or the Motiva indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

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

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

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities 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: 2010 – $7,500; 2011 – $4,300; 2012 – $1,400; 2013 – $1,400; 2014 – $1,000; 2015 and after – $4,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $8,100 in 2009, $5,100 in 2008 and $3,700 in 2007.

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

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

Chevron's environmental reserve as of December 31, 2009, was $1,700. Included in this balance were remediation activities at approximately 250 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 2009 was $185. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2009 environmental reserves balance of $1,515, $969 related to the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facililties, and pipelines. The remaining $546 was associated with various sites in international downstream ($107), upstream ($369) and other businesses ($70). 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.

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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 2009 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

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

Refer to Note 23 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

In accordance with accounting standards for asset retirement obligations (ASC 410), the company records the fair value of a liability for an asset retirement obligation (ARO) when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company's control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. The legal obligations associated with the retirement of the tangible long-lived assets require recognition in certain circumstances including: (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.

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

The following table indicates the changes to the company's before-tax asset retirement obligations in 2009, 2008 and 2007:

	2009	2008	2007
Balance at January 1	**$ 9,395**	$8,253	$5,773
Liabilities incurred	**144**	308	178
Liabilities settled	**(757)**	(973)	(818)
Accretion expense	**463**	430	399*
Revisions in estimated cash flows	**930**	1,377	2,721
Balance at December 31	**$ 10,175**	$9,395	$8,253

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

In the table above, the amounts associated with "Revisions in estimated cash flows" reflect increasing costs to abandon onshore and offshore wells, equipment and facilities. The long-term portion of the $10,175 balance at the end of 2009 was $9,289.

Note 24
Other Financial Information

Earnings in 2009 included gains of approximately $1,000 relating to the sale of nonstrategic properties. Of this amount, approximately $600 and $400 related to downstream and upstream assets, respectively. Earnings in 2008 included gains of approximately $1,200 relating to the sale of nonstrategic properties. Of this amount, approximately $1,000 related to upstream assets. Earnings 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		
	2009	2008	2007
Total financing interest and debt costs	**$ 301**	$ 256	$ 468
Less: Capitalized interest	**273**	256	302
Interest and debt expense	**$ 28**	$ –	$ 166
Research and development expenses	**$ 603**	$ 702	$ 510
Foreign currency effects*	**$ (744)**	$ 862	$(352)

* Includes $(194), $420 and $18 in 2009, 2008 and 2007, 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 $5,491 and $9,368 at December 31, 2009 and 2008, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO (charges) profits of $(168), $210 and $113 were included in earnings for the years 2009, 2008 and 2007, respectively.

The company has $4,618 in goodwill on the Consolidated Balance Sheet related to its 2005 acquisition of Unocal. Under the accounting standard for goodwill (ASC 350), the company tested this goodwill for impairment during 2009 and concluded no impairment was necessary.

Events subsequent to December 31, 2009, were evaluated until the time of the Form 10-K filing with the Securities and Exchange Commission on February 25, 2010.

Note 25
Assets Held for Sale

At December 31, 2009, the company reported no assets as "Assets held for sale" (AHS) on the Consolidated Balance Sheet. At December 31, 2008, $252 of net properties, plant and equipment were reported as AHS. Assets in this category are related to groups of service stations, aviation facilities, lubricants blending plants, and commercial and industrial fuels business. These assets were sold in 2009.

Note 26
Earnings Per Share

Basic earnings per share (EPS) is based upon Net Income Attributable to Chevron Corporation ("earnings") 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 20, "Stock Options and Other Share-Based Compensation," beginning on page 49). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2009	2008	2007
Basic EPS Calculation			
Earnings available to common stockholders – Basic[1]	**$ 10,483**	$ 23,931	$ 18,688
Weighted-average number of common shares outstanding	**1,991**	2,037	2,117
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,992**	2,038	2,118
Per share of common stock Earnings – Basic	**$ 5.26**	$ 11.74	$ 8.83
Diluted EPS Calculation			
Earnings available to common stockholders – Diluted[1]	**$ 10,483**	$ 23,931	$ 18,688
Weighted-average number of common shares outstanding	**1,991**	2,037	2,117
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**9**	12	14
Total weighted-average number of common shares outstanding	**2,001**	2,050	2,132
Per share of common stock Earnings – Diluted	**$ 5.24**	$ 11.67	$ 8.77

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