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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

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

For the transition period from ____________________ to ____________________

Commission file number: 001-32395

ConocoPhillips
(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

600 North Dairy Ashford
Houston, TX 77079
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **281-293-1000**

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

Title of each class	Name of each exchange on which registered
Common Stock, $.01 Par Value	New York Stock Exchange
Preferred Share Purchase Rights Expiring June 30, 2012	New York Stock Exchange
6.65% Debentures due July 15, 2018	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange
9.375% Notes due 2011	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $42.06, was $62.3 billion. The registrant, solely for the purpose of this required presentation, had deemed its Board of Directors and grantor trusts to be affiliates, and deducted their stockholdings of 811,943 and 39,808,419 shares, respectively, in determining the aggregate market value.

The registrant had 1,486,838,088 shares of common stock outstanding at January 31, 2010.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2010 (Part III)

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PART I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "forecast," "intend," "believe," "expect," "plan," "schedule," "target," "should," "goal," "may," "anticipate," "estimate" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 66.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is an international, integrated energy company. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

Our business is organized into six operating segments:

- **Exploration and Production (E&P)—**This segment primarily explores for, produces, transports and markets crude oil, natural gas, natural gas liquids and bitumen on a worldwide basis.
- **Midstream—**This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.
- **Refining and Marketing (R&M)—**This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia.
- **LUKOIL Investment—**This segment consists of our equity investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2009, our ownership interest was 20 percent based on issued shares and 20.09 percent based on estimated shares outstanding.
- **Chemicals—**This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC.
- **Emerging Businesses—**This segment represents our investment in new technologies or businesses outside our normal scope of operations.

At December 31, 2009, ConocoPhillips employed approximately 30,000 people.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 25—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

EXPLORATION AND PRODUCTION (E&P)

At December 31, 2009, our E&P segment represented 66 percent of ConocoPhillips' total assets. This segment primarily explores for, produces, transports and markets crude oil, natural gas, natural gas liquids and bitumen on a worldwide basis. Operations to liquefy natural gas and transport the resulting liquefied natural gas (LNG) are also included in the E&P segment. At December 31, 2009, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia.

The E&P segment does not include the financial results or statistics from our equity investment in the ordinary shares of LUKOIL, which are reported in our LUKOIL Investment segment. As a result, references to results, production, prices and other statistics throughout the E&P segment discussion exclude amounts related to our investment in LUKOIL. However, our share of LUKOIL is included in the "Oil and Gas Operations" disclosures, as well as in the net proved reserves table shown below.

The information listed below appears in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil and natural gas liquids, natural gas, bitumen and synthetic oil reserves.
- Net production of crude oil and natural gas liquids, natural gas, bitumen and synthetic oil.
- Average sales prices of crude oil and natural gas liquids, natural gas, bitumen and synthetic oil.
- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the “Oil and Gas Operations” disclosures following the Notes to Consolidated Financial Statements. Approximately 65 percent of our proved reserves are located in politically stable countries that belong to the “Organization for Economic Cooperation and Development.” Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2009**	2008	2007
Crude oil and natural gas liquids			
Consolidated operations	**3,194**	3,340	3,778
Equity affiliates	**1,710**	1,677	1,834
Total Crude Oil and Natural Gas Liquids	**4,904**	5,017	5,612
Natural gas			
Consolidated operations	**3,161**	3,360	3,750
Equity affiliates	**880**	798	490
Total Natural Gas	**4,041**	4,158	4,240
Bitumen			
Consolidated operations	**417**	100	85
Equity affiliates	**716**	700	623
Total Bitumen	**1,133**	800	708
Synthetic oil			
Consolidated operations	**248**	—	—
Equity affiliates	—	—	—
Total Synthetic Oil	**248**	—	—
Total consolidated operations	**7,020**	6,800	7,613
Total equity affiliates	**3,306**	3,175	2,947
Total company	**10,326**	9,975	10,560
Includes amounts related to LUKOIL investment:	***1,967***	*1,893*	*1,838*
Excludes Syncrude mining-related reserves (synthetic oil):	***n/a***	*249*	*221*

In 2009, E&P’s worldwide production, including its share of equity affiliates’ production other than LUKOIL, averaged 1,854,000 barrels of oil equivalent per day (BOED), compared with 1,789,000 in 2008. During 2009, 755,000 BOED were produced in the United States, a decrease from 775,000 in 2008. Production from our international E&P operations averaged 1,099,000 BOED in 2009, an increase compared with 1,014,000 in 2008. Worldwide production increased primarily due to new developments in the United Kingdom, Russia, China, Canada, Vietnam and Norway, in addition to less unplanned downtime. These increases were partially offset by field decline.

E&P’s worldwide annual average crude oil and natural gas liquids sales price decreased 37 percent, from $88.91 per barrel in 2008 to $55.63 in 2009. E&P’s average annual worldwide natural gas sales price decreased 48 percent, from $8.27 per thousand cubic feet in 2008 to $4.26 in 2009.

E&P—UNITED STATES

In 2009, U.S. E&P operations contributed 40 percent of E&P’s worldwide liquids production and 41 percent of natural gas production, compared with 43 percent for each in 2008.

Alaska

Greater Prudhoe Area

The Greater Prudhoe Area is composed of the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska’s North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas processing plant that processes and re-injects natural gas into the reservoir. Prudhoe Bay's satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven and Lisburne Fields are part of the Greater Point McIntyre Area. We have a 36.1 percent nonoperator interest in all fields within the Greater Prudhoe Area. Net oil and natural gas liquids production from the Greater Prudhoe Area averaged 119,000 barrels per day in 2009, compared with 123,000 in 2008.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, composed of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located about 40 miles west of Prudhoe Bay. Our ownership interest in the area is approximately 55 percent. Field installations include three central production facilities that separate oil, natural gas and water. The natural gas is either used for fuel or compressed for re-injection. Net oil production from the area averaged 65,000 barrels per day in 2009, compared with 67,000 in 2008.

Western North Slope

On the Western North Slope we operate the Colville River Unit, composed of the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located about 30 miles west of Kuparuk. Our ownership interest in the area is approximately 78 percent. Net production in 2009 was 68,000 barrels of oil per day, compared with 70,000 in 2008. Further development of potential satellite fields west of Alpine and into the National Petroleum Reserve—Alaska (NPRA) is contingent upon the receipt of permit approvals and additional exploration appraisal work. Planned development of one of these satellites, the Alpine West CD5 Project, has been postponed due to the denial of a key permit from the U.S. Army Corps of Engineers in February 2010. We expect to appeal their decision.

Cook Inlet Area

We operate the North Cook Inlet Unit, the Beluga River Unit, and the Kenai LNG Plant in the Cook Inlet Area. We have a 100 percent interest in the North Cook Inlet Unit, while we own 33.3 percent of the Beluga River Unit. Net production in 2009 from the Cook Inlet Area averaged 85 million cubic feet per day of natural gas, compared with 88 million in 2008. Production from the North Cook Inlet Unit is used primarily to supply our share of gas to the Kenai LNG Plant and also as a backup supply to local utilities, while gas from the Beluga River Unit is primarily sold to local utilities and is used as backup supply to the Kenai LNG Plant.

We have a 70 percent interest in the Kenai LNG Plant, which supplies LNG to two utility companies in Japan. We sold 21 net billion cubic feet of LNG in 2009, compared with 27 billion in 2008.

Exploration

In a February 2008 lease sale conducted by the U.S. Department of Interior (DOI) under the Outer Continental Shelf (OCS) Lands Act, we successfully bid, and were awarded 10-year primary term leases, on 98 blocks in the Chukchi Sea, for total bid payments of $506 million. Various special interest groups have brought two separate lawsuits challenging (1) the DOI's entire OCS leasing program, and (2) the Chukchi Sea lease sale conducted by the DOI under that program. In the first suit, the Court ordered the DOI to reconsider one aspect of its OCS leasing program. The results of the DOI's reconsideration are expected during the first quarter of 2010. In the second suit, briefs have been filed on behalf of the defendants, including the DOI, in support of the Chukchi Sea lease sale, and a decision is expected later in 2010. We continue to progress plans for drilling an exploration well on our Chukchi Sea leases no earlier than 2012. In January 2010, we exchanged a 25 percent working interest in 50 of these leases for cash consideration and additional working interests in the Lower Tertiary play of the deepwater Gulf of Mexico.

Two exploration wells were drilled in the Greater Mooses Tooth Unit, located in the NPRA. One of the wells was expensed as a dry hole, while the second well encountered hydrocarbons. We are evaluating the potential for future development of this latest discovery.

Transportation

We transport the petroleum liquids produced on the North Slope to south-central Alaska through an 800-mile pipeline that is part of the Trans-Alaska Pipeline System (TAPS). We have a 28.3 percent ownership interest in TAPS, and we also have ownership interests in the Alpine, Kuparuk and Oliktok Pipelines on the North Slope.

Our wholly owned subsidiary, Polar Tankers, Inc., manages the marine transportation of our North Slope production, using five company-owned double-hulled tankers in addition to chartering third-party vessels as necessary.

In 2008, ConocoPhillips and BP plc formed a limited liability company to progress the pipeline project named Denali—The Alaska Gas Pipeline. The project would move Alaska natural gas to North American markets. Denali has continued to progress the project in preparation for its open season in 2010, during which the pipeline company will seek customers to make long-term firm transportation commitments to the project. There is a pipeline project competing with Denali that is structured under the Alaska Gasline Inducement Act.

U.S. Lower 48

Gulf of Mexico

At year-end 2009, our portfolio of producing properties in the Gulf of Mexico mainly consisted of one operated field and three fields operated by co-venturers, including:

- 75 percent operator interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 16 percent nonoperator interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 16 percent nonoperator interest in the Princess Field, a northern, subsalt extension of the Ursa Field.
- 12.4 percent nonoperator interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

Net production from our Gulf of Mexico properties averaged 21,000 barrels per day of liquids and 28 million cubic feet per day of natural gas in 2009, compared with 18,000 barrels per day and 24 million cubic feet per day in 2008.

Onshore

Our 2009 onshore production principally consisted of natural gas, with the majority of production located in the San Juan Basin, Permian Basin, Lobo Trend, Bossier Trend, and panhandles of Texas and Oklahoma. We also have operations in the Wind River, Anadarko and Fort Worth Basins, as well as in East Texas and northern and southern Louisiana. Other onshore ownership includes properties in the Williston Basin, the Piceance Basin and the Cedar Creek Anticline.

Onshore activities in 2009 were mostly centered on continued optimization and development of existing assets. Combined net production from all Lower 48 onshore fields in 2009 averaged 1,899 million cubic feet per day of natural gas and 145,000 barrels per day of liquids, compared with 1,970 million cubic feet per day and 147,000 barrels per day in 2008.

The San Juan Basin, located in northwestern New Mexico and southwestern Colorado, includes the majority of our U.S. coalbed methane (CBM) production. Additionally, we continue to pursue development opportunities in three conventional formations in the San Juan Basin. Net production from San Juan averaged 903 million cubic feet per day of natural gas and 49,000 barrels per day of liquids in 2009, compared with 863 million cubic feet per day and 48,000 barrels per day in 2008.

Transportation

In 2006, we acquired a 24 percent interest in West2East Pipeline LLC, which merged into Rockies Express Pipeline LLC in December 2009. In November 2009, Rockies Express completed construction of a 1,679-mile natural gas pipeline from Colorado to Ohio, which has the capacity to deliver 1.8 billion cubic feet of natural gas per day to eastern markets. We increased our ownership interest to 25 percent upon project completion.

Exploration

During 2009, we participated in two significant discoveries in the deepwater Gulf of Mexico. We hold an 18 percent interest in the Tiber discovery and a 40 percent interest in the Shenandoah discovery. Both discoveries require future appraisal drilling. In addition, we were the successful bidder on 27 blocks in the March and August 2009 federal offshore lease sales. At year end, we had interests in 287 lease blocks totaling

1.1 million net acres in the Gulf of Mexico. In January 2010, we exchanged a 25 percent working interest in 50 of our leases in the Chukchi Sea for cash consideration and additional working interests in the Lower Tertiary play of the deepwater Gulf of Mexico.

We drilled and completed 52 gross onshore exploration wells. The majority of the wells were located in the Bakken play in the Williston Basin and the Fort Worth Basin Barnett play. We have seen encouraging results from initial wells in our Eagle Ford play in South Texas where we have accumulated over 240,000 acres. Other areas with active exploration drilling programs included Wyoming, Colorado and East Texas.

E&P—EUROPE

In 2009, E&P operations in Europe contributed 23 percent of E&P's worldwide liquids production, compared with 24 percent in 2008. European operations contributed 18 percent of natural gas production in 2009, compared with 20 percent in 2008. Our European assets are principally located in the Norwegian and U.K. sectors of the North Sea.

Norway

We operate and hold a 35.1 percent interest in the Greater Ekofisk Area, located approximately 200 miles offshore Norway in the North Sea. The Greater Ekofisk Area is composed of four producing fields: Ekofisk, Eldfisk, Embla and Tor. Net production in 2009 from the Greater Ekofisk Area was 92,000 barrels of liquids per day and 89 million cubic feet of natural gas per day, compared with 99,000 barrels per day and 100 million cubic feet per day in 2008.

We also have varying ownership interests in other producing fields in the Norwegian sector of the North Sea and in the Norwegian Sea, including:

- 24.3 percent interest in the Heidrun Field.
- 20 percent interest in the Alvheim Field.
- 10.3 percent interest in the Statfjord Field.
- 23.3 percent interest in the Huldra Field.
- 1.6 percent interest in the Troll Field.
- 9.1 percent interest in the Visund Field.
- 6.2 percent interest in the Grane Field.
- 2.4 percent interest in the Oseberg Area.

Net production from these and other fields in the Norwegian sector of the North Sea and the Norwegian Sea averaged 68,000 barrels of liquids per day and 128 million cubic feet of natural gas per day in 2009, compared with 68,000 barrels per day and 139 million cubic feet per day in 2008.

Transportation

We have interests in the transportation and processing infrastructure in the Norwegian sector of the North Sea, including interests in the Norpipe Oil Pipeline System and in Gassled, which owns most of the Norwegian gas transportation system.

Exploration

We participated in eight wells in 2009, with six of the wells encountering hydrocarbons. Two discoveries were made on the Visund East flank, two discoveries were made in the Oseberg Area and two discoveries were made in the Alvheim Area. We were also awarded an additional 128,000 acres in 2009.

United Kingdom

In addition to our 58.7 percent interest in the Britannia natural gas and condensate field, we own 50 percent of Britannia Operator Limited, the operator of the field. We also have an 83.5 percent interest and a 75 percent interest in the Callanish and Brodgar Britannia satellite fields, respectively. Net production from Britannia and its satellite fields averaged 304 million cubic feet of natural gas per day and 40,000 barrels of liquids per day in 2009, compared with 277 million cubic feet per day and 24,000 barrels per day in 2008.

We operate and hold a 36.5 percent interest in the Judy/Joanne Fields, which together make up J-Block. Additionally, our operated Jade Field, in which we hold a 32.5 percent interest, produces from a wellhead platform and pipeline tied to the J-Block facilities. Together, these fields produced a net 12,000 barrels of liquids per day and 96 million cubic feet of natural gas per day in 2009, compared with 13,000 barrels per day and 88 million cubic feet per day in 2008.

Our various ownership interests in 18 producing gas fields in the Rotliegendes and Carboniferous Areas of the southern North Sea yielded average net production in 2009 of 185 million cubic feet per day of natural gas, compared with 241 million in 2008.

We also have ownership interests in several other producing fields in the U.K. sector of the North Sea. Net production from these fields averaged 16,000 barrels of liquids per day and 12 million cubic feet of natural gas per day in 2009, compared with 17,000 barrels per day and 14 million cubic feet per day in 2008.

In the Atlantic Margin, we have a 24 percent interest in the Clair Field. Net production in 2009 averaged 12,000 barrels of liquids per day, compared with 11,000 in 2008.

The Millom, Dalton and Calder Fields in the East Irish Sea, in which we have a 100 percent ownership interest, are operated on our behalf by a third party. Net production in 2009 averaged 60 million cubic feet of natural gas per day, compared with 43 million in 2008.

Transportation

The Interconnector Pipeline, linking the United Kingdom and Belgium, facilitates marketing natural gas produced in the United Kingdom throughout Europe. Our 10 percent equity share allows us to ship approximately 200 million cubic feet of natural gas per day to markets in continental Europe, and our reverse-flow rights provide an 85 million cubic feet per day import capability into the United Kingdom.

We operate the Teesside oil and Theddlethorpe gas terminals, in which we have 29.3 percent and 50 percent ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party, in the United Kingdom.

Exploration

We participated in three exploration wells in 2009. One well was a discovery, one was expensed as a dry hole and the third was drilling at year end. The discovery was made in the Southern Gas Basin and began production in 2009.

Poland

Exploration

In 2009, we entered into a shale gas venture in Poland that provides us with the opportunity to evaluate and earn a 70 percent interest in six exploration licenses in the Baltic Basin. We acquired seismic data in 2009 and intend to drill our first well in 2010.

E&P—CANADA

In 2009, E&P operations in Canada contributed 11 percent of E&P's worldwide liquids production, compared with 10 percent in 2008. Canadian operations contributed 22 percent of E&P's worldwide natural gas production in 2009, the same as in 2008.

Western Canada

Operations in western Canada encompass oil and gas properties throughout Alberta, northeastern British Columbia, and southern Saskatchewan. Net production from western Canada averaged 1,062 million cubic feet per day of natural gas and 40,000 barrels per day of liquids in 2009, compared with 1,054 million cubic feet per day and 44,000 barrels per day in 2008.

Surmont

We operate and have a 50 percent interest in the Surmont oil sands lease, located approximately 35 miles south of Fort McMurray, Alberta. The Surmont project uses an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD). The average net production of bitumen from Surmont during 2009 was 7,000 barrels per day, compared with 6,000 barrels per day in 2008, with net peak production of 12,000 barrels per day expected in 2013. Surmont Phase II was sanctioned in 2009 and is expected to begin producing in 2015, increasing Surmont's net production to 50,000 barrels per day in 2017.

FCCL

In 2007, we formed two 50/50 business ventures with EnCana Corporation (now Cenovus Energy Inc.) to create an integrated North American heavy oil business: FCCL Partnership, a Canadian upstream general partnership, and WRB Refining LLC, a U.S. downstream limited liability company. FCCL's assets, operated by Cenovus, consist of the Foster Creek and Christina Lake SAGD bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. Our share of FCCL's production increased to 43,000 barrels per day in 2009, compared with 30,000 barrels per day in 2008, primarily due to Foster Creek Phases 1D and 1E commencing operations late in the first quarter of 2009 and continuing to ramp-up throughout the year. Construction of Christina Lake Phase 1C continued through the year, and in the fourth quarter of 2009, we sanctioned Christina Lake Phase 1D. See the Refining and Marketing (R&M) section for information on WRB.

Syncrude Canada Ltd.

We own a 9 percent interest in the Syncrude Canada Ltd. (SCL) joint venture, created for the purpose of mining shallow deposits of oil sands, extracting the bitumen, and upgrading it into a light sweet synthetic crude oil called Syncrude. The primary plant and facilities are located at Mildred Lake, about 25 miles north of Fort McMurray, Alberta. SCL, as operator of the joint venture, holds eight oil sands leases and the associated surface rights, of which our share is approximately 22,400 net acres. Net production averaged 23,000 barrels per day in 2009, compared with 22,000 in 2008.

Parsons Lake/Mackenzie Gas Project

We are working with three other energy companies, as members of the Mackenzie Delta Producers' Group, on the development of the Mackenzie Valley Pipeline and gathering system, which is proposed to transport onshore gas production from the Mackenzie Delta in northern Canada to established markets in North America. We have a 75 percent interest in the Parsons Lake gas field, one of the primary fields in the Mackenzie Delta, which would anchor the pipeline development. The Joint Review Panel, an independent body appointed by the Minister of Environment to evaluate the potential impacts of the project on the environment and lives of the people in the project area, conditionally recommended approval of the project in December 2009. We anticipate the Mackenzie Delta Producers' Group will continue to pursue needed regulatory authorizations, but detailed engineering work has been deferred pending resolution with the federal government on the fiscal and commercial framework.

Exploration

We hold exploration acreage in four areas of Canada: offshore eastern Canada, onshore western Canada, the Mackenzie Delta/Beaufort Sea Region, and the Arctic Islands. During 2009, we began drilling an exploration well in the Laurentian Basin, located offshore eastern Canada that continued into 2010. We also acquired an additional 900,000 acres in the Laurentian Basin in 2009. In western Canada, we participated in 27 wells resulting in 23 discoveries. We also acquired an additional 71,000 acres, including over 22,000 acres in the Horn River shale gas play, increasing our position to nearly 100,000 acres. In the Beaufort Sea Region, we acquired additional interest in the Amauligak Strategic Discovery License.

E&P—SOUTH AMERICA

Venezuela

Petrozuata, Hamaca and Corocoro

On June 26, 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government's Nationalization Decree. In response, Venezuela's national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates directly assumed the activities associated with and control over ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. For additional information, see the "Expropriated Assets" section of Note 10—Impairments, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Plataforma Deltana Block 2

We sold our 40 percent nonoperating interest in Plataforma Deltana Block 2 to PDVSA during 2009.

Peru

Exploration

At year-end 2009, we held ownership interests in four exploration blocks in Peru. Final preparations are under way for a 2D seismic program scheduled for 2010 in Block 39. We operate Blocks 123, 124 and 129, and are continuing preparations for a 2D seismic program scheduled to commence in the first quarter of 2010. We relinquished Block 104 during 2009.

Ecuador

In April 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before the World Bank's International Centre for Settlement of Investment Disputes (ICSID) against The Republic of Ecuador and PetroEcuador as a result of the newly-enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by the ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. As a result, our assets in Ecuador were effectively expropriated. In the third quarter of 2009, Ecuador took over operations in Block 7 and 21, formalizing the complete expropriation of our assets. A jurisdictional hearing before the ICSID was held in January 2010, with the outcome still pending. For additional information, see the "Expropriated Assets" section of Note 10—Impairments, in the Notes to Consolidated Financial Statements.

E&P—ASIA PACIFIC/MIDDLE EAST

In 2009, E&P operations in the Asia Pacific/Middle East Region contributed 13 percent of E&P's worldwide liquids production and 16 percent of natural gas production, compared with 11 percent and 13 percent in 2008, respectively.

Australia and Timor Sea

Australia Pacific LNG

In October 2008, we closed on a transaction with Origin Energy, an integrated Australian energy company, to further enhance our long-term Australasian natural gas business. The 50/50 joint venture, named Australia Pacific LNG (APLNG), is focused on CBM production from the Bowen and Surat Basins in Queensland, Australia, and LNG processing and export sales. With this transaction, we gained access to CBM resources in Australia and will enhance our LNG position with the expected creation of an additional LNG hub targeting Asia Pacific markets. Multiple LNG trains are anticipated. Over 20,000 gross wells are ultimately envisioned to supply both the domestic gas market and the LNG development. Drilling and production operations will be supported by gas gathering systems and centralized gas processing and compression stations, as well as water treatment facilities.

Our share of the joint venture's production in 2009 was 84 million cubic feet per day of natural gas. Current production is sold into the Australian domestic market. CBM field development work is ongoing in parallel with front-end engineering associated with the planned LNG processing facilities. During 2009, Laird Point was selected as the future site for LNG facilities. Final investment decision on the initial LNG trains is planned for the fourth quarter of 2010.

Bayu-Undan

We operate and hold a 57.2 percent ownership interest in the Bayu-Undan Field located in the Timor Sea. The field averaged a net production rate of 35,000 barrels of liquids per day in 2009, compared with 36,000 in 2008. Our share of natural gas production was 216 million cubic feet per day in 2009, compared with

210 million in 2008. Produced natural gas is used to supply the Darwin LNG Plant, in which we own a 57.2 percent interest. In 2009, we sold 156 billion gross cubic feet of LNG to utility customers in Japan, compared with 159 billion in 2008.

Greater Sunrise

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. Although agreement has been reached between the governments of Australia and Timor-Leste concerning sharing of revenues from the anticipated development of Greater Sunrise, key challenges to be resolved before significant funding commitments can be made include gaining co-venturer and government alignment on the development concept, and establishing fiscal stability arrangements.

Western Australia

In 2009, our share of production from the Athena/Perseus (WA-17-L) gas field, located offshore Western Australia, was 35 million cubic feet of natural gas per day, the same as in 2008.

Exploration

During 2009, we drilled two exploration wells and started a third in the offshore Browse Basin. The first well, Poseidon-1, was a significant discovery. Poseidon-2, the initial appraisal well for the discovery, encountered hydrocarbons in some of the same sands as were seen in the discovery well and is currently being evaluated. A seismic survey has recently been acquired over the discovery. Additionally, Kontiki-1 was drilled on a prospect independent from Poseidon and was expensed as a dry hole. We intend to drill at least one additional well in the Browse Basin in 2010.

Qatar

Qatargas 3 is an integrated project jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). The project comprises upstream natural gas production facilities to produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field. The project also includes a 7.8 million-gross-ton-per-year LNG facility, from which LNG will be shipped in new, leased LNG carriers destined for sale in the United States and other markets. The first LNG cargoes are expected to be loaded in the second half of 2010.

In order to capture cost savings, Qatargas 3 is executing the development of the onshore and offshore assets as a single integrated project with Qatargas 4, a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This includes the joint development of offshore facilities situated in a common offshore block in the North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the Qatargas 3 and Qatargas 4 joint ventures. Upon completion of the Qatargas 3 and Qatargas 4 Projects, production from the LNG plant and associated facilities will be combined and shared.

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline. The terminal is currently under construction adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. Subject to the negotiation of definitive agreements, ConocoPhillips will hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatargas 3 and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines.

Indonesia

We operate seven production sharing contracts (PSCs) in Indonesia. Three of these PSCs are in various stages of development from which net production grew to an average of 447 million cubic feet per day of natural gas and 19,000 barrels per day of liquids in 2009, compared with 343 million cubic feet per day and 17,000 barrels per day in 2008. Our producing assets are primarily concentrated in two core areas: the South Natuna Sea and onshore South Sumatra.

South Natuna Sea Block B

The offshore South Natuna Sea Block B PSC, in which we have a 40 percent interest and are the operator, has two producing oil fields and 16 natural gas fields in various stages of development. Natural gas production is sold under international sales agreements to Malaysia and Singapore. The North Belut Field in Block B achieved first gas production in November 2009.

South Sumatra

These onshore blocks are comprised of the Corridor and South Jambi B PSCs. The Corridor PSC, in which we have a 54 percent interest, has six oil fields and six natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. We have a 45 percent interest in the South Jambi B PSC, which supplies natural gas to Singapore.

Exploration

We operate three offshore exploration PSCs: Amborip VI, Kuma and Arafura Sea, where exploration drilling is scheduled to take place in the fourth quarter of 2010 and the first quarter of 2011. We also operate the Warim onshore exploration PSC in Papua.

Transportation

We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

China

We are the operator and have a 49 percent share of the Peng Lai 19-3 Field in Bohai Bay Block 11-05, as well as the nearby Peng Lai 19-9 and Peng Lai 25-6 Fields. As part of our Bohai Bay Phase II Project, a floating production, storage and offloading (FPSO) vessel to accommodate production from these fields was installed in May 2009. Development of Peng Lai 19-3 continues. Net production averaged 33,000 barrels of oil per day in 2009, compared with 14,000 in 2008. Production should continue to ramp-up over the next two years, with annual average net production of 69,000 barrels of oil per day anticipated in 2011.

The Xijiang development consists of two fields located approximately 80 miles south of Hong Kong in the South China Sea. Combined net production of oil from the Xijiang Fields averaged 5,000 barrels per day in 2009, compared with 7,000 in 2008. Under the terms of the contract, our ownership rights in the 24-3/1 Field ended in January 2010, and our rights in the 30-2 Field will end in November 2010. Our ownership in these fields was 24.5 percent and 12.3 percent, respectively, at December 31, 2009.

We have a 24.5 percent interest in the offshore Panyu Field, also located in the South China Sea, which produced 11,000 net barrels of oil per day in 2009 and 12,000 in 2008.

Exploration

We entered a pilot evaluation program in a coalbed methane play in the onshore Qinshui Basin in 2009. The pilot program is expected to last between 12-18 months and will involve drilling and monitoring the production performance of a series of horizontal wells. At the end of the program, we will have the option to elect an assignment of a 30 percent interest in three PSCs covering the play. We drilled two exploration wells on our existing offshore Bohai Block BZ 11/05, both of which were expensed as dry holes.

Vietnam

Our ownership interest in Vietnam is centered around the Cuu Long Basin in the South China Sea and consists of two primarily oil-producing blocks and one gas pipeline transportation system.

We have a 23.3 percent interest in Block 15-1 in the Cuu Long Basin. Net production in 2009 was 22,000 barrels of oil per day, compared with 13,000 in 2008. The oil is processed through a 1 million barrel FPSO vessel and through the Su Tu Vang central processing platform and floating storage and offloading (FSO) vessel.

Also in the Cuu Long Basin, we have a 36 percent interest in the Rang Dong Field in Block 15-2. All wellhead platforms produce into an FSO vessel. Net production in 2009 was 7,000 barrels per day of liquids and 15 million cubic feet per day of natural gas, compared with 9,000 barrels per day and 16 million cubic feet per day in 2008.

Transportation

We own a 16.3 percent interest in the Nam Con Son natural gas pipeline. This 244-mile transportation system links gas supplies from the Nam Con Son Basin to gas markets in southern Vietnam.

Malaysia

We have interests in three deepwater PSCs located off the eastern Malaysian state of Sabah: Block G, Block J, and the Kebabangan Cluster. Development of the Gumusut deepwater oil discovery in Block J is currently under way and includes the installation of a semi-submersible oil production platform.

Exploration

We participated in two exploration wells during 2009, a successful appraisal of the Petai discovery on Block G, and the Sigapon 1 Well in Block J, which was expensed as a dry hole.

Bangladesh

Exploration

We were formally awarded two deepwater blocks in offshore Bangladesh in 2009. PSC negotiations continue into 2010.

Abu Dhabi

In July 2009, we signed the Shah Gas Field Joint Venture and Field Entry agreements with the Abu Dhabi National Oil Company to progress the Shah Gas Field Project. This large-scale project involves the development of natural gas condensate reservoirs within the onshore Shah gas field, the construction of a new 1 billion-cubic-feet-per-day natural gas processing plant at Shah, new natural gas and gas liquids pipelines, and sulfur-exporting facilities at Ruwais. A final investment decision is expected in 2010, and we hold a 40 percent interest in the proposed project.

E&P—AFRICA

During 2009, E&P operations in Africa contributed 7 percent of E&P's worldwide liquids production and 2 percent of natural gas production, compared with 8 percent and 2 percent, respectively, in 2008.

Nigeria

During 2009, we produced from four onshore Oil Mining Leases (OMLs), in which we have a 20 percent nonoperator interest. Net production from these leases was 19,000 barrels of liquids per day and 111 million cubic feet of natural gas per day in 2009, compared with 21,000 barrels per day and 105 million cubic feet per day in 2008.

We have a 20 percent interest in a 480-megawatt gas-fired power plant in Kwale, Nigeria, which supplies electricity to Nigeria's national electricity supplier. In 2009, the plant consumed 12 million net cubic feet per day of natural gas sourced from our proved reserves in the OMLs.

We have a 17 percent equity interest in Brass LNG Limited, which plans to construct an LNG facility in the Niger Delta.

Exploration

Development studies continue for the Uge discovery in offshore deepwater Block OPL 214. Onshore, we participated in the start of the Obiafu SW Deep B exploration well, but the well was abandoned and expensed due to pad location problems. We plan to redrill the well in 2010.

Libya

ConocoPhillips holds a 16.3 percent interest in the Waha concessions in Libya, which encompass nearly 13 million gross acres. Net oil production averaged 45,000 barrels per day in 2009, versus 47,000 in 2008.

Algeria

We have interests in three fields in Block 405a: the Menzel Lejmat North Field, the Ourhoud Field, and the development stage El Merk oil field unit. The El Merk Project was sanctioned in 2009 and is expected to begin producing in 2012. Net production from these fields averaged 14,000 barrels of oil per day in 2009, compared with 13,000 in 2008.

E&P—RUSSIA

NMNG

We have a 30 percent ownership interest with a 50 percent governance interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL. NMNG is working to develop resources in the northern part of Russia's Timan-Pechora province, including the Yuzhno Khylchuyu (YK) Field. Initial production from YK was achieved in June 2008. Net production from the joint venture averaged 46,000 barrels per day in 2009, compared with 13,000 in 2008. Production from the NMNG joint venture fields is transported via pipeline to LUKOIL's terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets.

Polar Lights

We have a 50 percent equity interest in Polar Lights Company, an entity that owns producing fields in the Timan-Pechora Basin in northern Russia. Net production averaged 9,000 barrels of oil per day in 2009, compared with 11,000 in 2008.

E&P—CASPIAN

In the Caspian Sea, we have an 8.4 percent interest in the Republic of Kazakhstan's North Caspian Sea Production Sharing Agreement, which includes the Kashagan Field. The first phase of field development currently being executed includes construction of artificial drilling islands with processing facilities and living quarters, and pipelines to carry production onshore. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years. A joint operating company oversees the Kashagan development, and expects first production in late 2012.

Transportation

We have a 2.5 percent interest in the Baku-Tbilisi-Ceyhan Pipeline, which transports crude oil from the Caspian Region through Azerbaijan, Georgia and Turkey for tanker loadings at the port of Ceyhan.

Exploration

In 2009, we acquired a 24.5 percent interest in the N Block, located offshore Kazakhstan. In addition, appraisal drilling and development studies continue for the next phase of Kashagan and the satellite fields of Kalamkas, Kairan and Aktote.

E&P—OTHER

LNG

We have a long-term agreement with Freeport LNG Development, L.P. to use 0.9 billion cubic feet per day of regasification capacity at Freeport's 1.5 billion-cubic-feet-per-day LNG receiving terminal in Quintana, Texas. Due to present market conditions, which favor the flow of LNG to European and Asian markets, our near-to-mid-term utilization of the Freeport Terminal is expected to be limited. We are responsible for monthly process-or-pay payments to Freeport irrespective of whether we utilize the terminal for regasification. The financial impact of this capacity underutilization is not expected to be material to our future earnings or cash flows.

Commercial

Our Commercial organization optimizes the commodity flows of our E&P segment. This group markets our crude oil and natural gas production, using commodity buyers, traders and marketers in offices in the United States, the United Kingdom, Singapore, Canada and Dubai.

E&P—RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2009. No difference exists between our estimated total proved reserves for year-end 2008 and year-end 2007, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2009.

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DELIVERY COMMITMENTS

We sell crude oil and natural gas from our E&P producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 6 trillion cubic feet of natural gas and 60 million barrels of crude oil in the future, including approximately 800 billion cubic feet related to the minority interests of consolidated subsidiaries. These contracts have various expiration dates through the year 2025. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill these commitments. See the disclosure on “Proved Undeveloped Reserves” in the “Oil and Gas Operations” section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

MIDSTREAM

At December 31, 2009, our Midstream segment represented 1 percent of ConocoPhillips’ total assets. Our Midstream business is primarily conducted through our 50 percent equity investment in DCP Midstream, LLC, a joint venture with Spectra Energy.

The Midstream business purchases raw natural gas from producers and gathers natural gas through extensive pipeline gathering systems. The gathered natural gas is then processed to extract natural gas liquids. The remaining “residue” gas is marketed to electrical utilities, industrial users and gas marketing companies. Most of the natural gas liquids are fractionated—separated into individual components like ethane, butane and propane—and marketed as chemical feedstock, fuel or blendstock. Total natural gas liquids extracted in 2009, including our share of DCP Midstream, were 187,000 barrels per day, compared with 188,000 in 2008.

DCP Midstream markets a portion of its natural gas liquids to ConocoPhillips and Chevron Phillips Chemical Company LLC under a supply agreement that continues until December 31, 2014. Beginning in 2015, the volume commitment is reduced by 20 percent each year until the volume commitment is zero. This purchase commitment is on an “if-produced, will-purchase” basis and is expected to have a relatively stable purchase pattern over the remaining term of the contract. Under the agreement, natural gas liquids are purchased at various published market index prices, less transportation and fractionation fees.

DCP Midstream is headquartered in Denver, Colorado. At December 31, 2009, DCP Midstream owned or operated 53 natural gas liquids extraction and 10 natural gas liquids fractionation plants, and its gathering and transmission systems included approximately 60,000 miles of pipeline. In 2009, DCP Midstream’s raw natural gas throughput averaged 6.1 billion cubic feet per day, and natural gas liquids extraction averaged 358,000 barrels per day, compared with 6.2 billion cubic feet per day and 360,000 barrels per day in 2008. DCP Midstream’s assets are primarily located in the following producing regions of the United States: Rocky Mountains, Midcontinent, Permian, East Texas/North Louisiana, South Texas, Central Texas and Gulf Coast. Outside of DCP Midstream, our U.S. natural gas liquids business included the following as of year-end 2009:

- A 25,000 barrel-per-day capacity natural gas liquids fractionation plant in Gallup, New Mexico.
- A 22.5 percent equity interest in Gulf Coast Fractionators, which owns a natural gas liquids fractionation plant in Mont Belvieu, Texas (with our net share of capacity at 24,300 barrels per day).
- A 40 percent interest in a fractionation plant in Conway, Kansas (with our net share of capacity at 43,200 barrels per day).
- A 12.5 percent equity interest in a fractionation plant in Mont Belvieu, Texas (with our net share of capacity at 26,000 barrels per day).
- A commercial trading organization based in Houston, Texas, that optimizes the flow of natural gas liquids and markets propane on a wholesale basis.

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited, which processes natural gas in Trinidad and markets natural gas liquids in the Caribbean, Central America and the U.S. Gulf Coast. Its facilities include a 2 billion-cubic-feet-per-day gas processing plant and a 70,000 barrel-per-day natural gas liquids fractionator. A third gas processing train was completed in July 2009, which increased total processing capacity to 2 billion cubic feet per day. Our share of natural gas liquids extracted averaged 8,000 barrels per day in 2009 and 2008. Our share of fractionated liquids averaged 17,000 barrels per day in 2009, compared with 14,000 in 2008.

REFINING AND MARKETING (R&M)

At December 31, 2009, our R&M segment represented 24 percent of ConocoPhillips' total assets. R&M operations encompass refining crude oil and other feedstocks into petroleum products (such as gasolines, distillates and aviation fuels); buying, selling and transporting crude oil; and buying, transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and the Asia Pacific Region. The R&M segment does not include the results or statistics from our equity investment in LUKOIL, which are reported in our LUKOIL Investment segment.

Our Commercial organization optimizes the commodity flows of our R&M segment. This organization procures feedstocks for R&M's refineries, facilitates supplying a portion of the gas and power needs of the R&M facilities, supplies petroleum products to our marketing operations, and markets petroleum products directly to third parties. Commercial has buyers, traders and marketers in offices in the United States, the United Kingdom, Singapore, Canada and Dubai.

R&M—UNITED STATES

Refining

At December 31, 2009, we owned or had an interest in 12 operated refineries in the United States.

Refinery	Location	Ownership	Net Crude Throughput Capacity (MBD)
East Coast Region			
Bayway	Linden, New Jersey	100.00%	238
Trainer	Trainer, Pennsylvania	100.00	185
			423
Gulf Coast Region			
Alliance	Belle Chasse, Louisiana	100.00	247
Lake Charles	Westlake, Louisiana	100.00	239
Sweeny	Old Ocean, Texas	100.00	247
			733
Central Region			
Wood River	Roxana, Illinois	50.00	153
Borger	Borger, Texas	50.00	73
Ponca City	Ponca City, Oklahoma	100.00	187
			413
West Coast Region			
Billings	Billings, Montana	100.00	58
Ferndale	Ferndale, Washington	100.00	100
Los Angeles	Carson/Wilmington, California	100.00	139
San Francisco	Arroyo Grande/San Francisco, California	100.00	120
			417
			1,986

Primary crude oil characteristics and sources of crude oil for our U.S. refineries are as follows:

	Characteristics				Sources				
	Sweet	Medium Sour	Heavy Sour	High TAN*	United States	Canada	South America	Europe & FSU**	Middle East & Africa
Bayway	•					•		•	•
Trainer	•					•			•
Alliance	•				•				•
Lake Charles	•	•	•	•	•		•		
Sweeny	•		•	•			•		•
Wood River	•	•	•	•	•	•			•
Borger		•	•		•	•			
Ponca City	•	•	•		•	•	•		
Billings		•	•		•	•			
Ferndale	•	•			•	•			
Los Angeles		•	•	•	•	•	•		•
San Francisco	•		•	•	•		•		

* *High TAN (Total Acid Number): acid content greater than or equal to 1.0 milligram of potassium hydroxide (KOH) per gram.*

** *Former Soviet Union.*

Capacities for and yields of clean products, as well as other products produced, relating to our U.S. refineries are as follows:

	Clean Product Capacity (MBD)			Other Refined Product Output				
	Gasolines	Distillates	Clean Product Yield Capability	Fuel Oil & Other Heavy Intermediates	Natural Gas Liquids	Petroleum Coke	Petro-chemical Feedstock	Asphalt
Bayway	145	110	90%	•	•		•	
Trainer	105	65	85	•	•			
Alliance	125	120	88	•	•	•	•	
Lake Charles	90	110	69	•	•	• **		
Sweeny	130	120	86	•	•	•	•	
Wood River*	83	45	80	•	•	•	•	•
Borger*	55	28	89		•	•	•	
Ponca City	105	75	90	•	•	•		
Billings	35	25	89		•	•		
Ferndale	55	30	75	•				
Los Angeles	85	61	86			•		
San Francisco	52	52	87	•	•	•		

* *Represents our proportionate share.*

** *Includes specialty coke.*

MSLP

Merey Sweeny, L.P. (MSLP) is a limited partnership that owns a 70,000 barrel-per-day delayed coker and related facilities at the Sweeny Refinery used to produce fuel-grade petroleum coke. Prior to August 28, 2009, MSLP was owned 50/50 by us and PDVSA. Under the agreements that govern the relationships between the partners, certain defaults by PDVSA with respect to supply of crude oil to the Sweeny Refinery gave us the right to acquire PDVSA's 50 percent ownership interest in MSLP. On August 28, 2009, we exercised that right. In public statements, PDVSA has challenged our actions. We continue to use the equity method of accounting for our investment in MSLP.

WRB

In 2007, we closed on a business venture with EnCana Corporation (now Cenovus) to create an integrated North American heavy oil business. This venture consists of two 50/50 business ventures: a Canadian upstream general partnership, FCCL Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. WRB consists of the Wood River and Borger Refineries, located in Roxana, Illinois, and Borger, Texas, respectively. We are the operator and managing partner of WRB. See the “Exploration and Production (E&P)” section for additional information on FCCL.

Since formation, the joint venture has expanded the processing capability of heavy Canadian crude to 95,000 barrels per day from 60,000 barrels per day with the startup of a coker at Borger in 2007. In addition, during 2008, the final permit was received and plans were progressed to expand the Wood River Refinery, including the installation of a coker. With the completion of this project, anticipated in 2011, total processing capability of heavy Canadian or similar crudes at Wood River will increase to 225,000 barrels per day, and the majority of the existing asphalt production at the refinery will be replaced with production of upgraded products.

Capital Projects

In 2009, capital was directed toward projects to meet environmental and air emission standards and to further improve the operating reliability, safety and energy efficiency of processing units. During 2009, we expanded a hydrocracker at the Rodeo facility of our San Francisco Refinery. The hydrocracker was commissioned in September 2009, resulting in a 12 percent increase in clean product yield.

Marketing

In the United States as of December 31, 2009, we marketed gasoline, diesel and aviation fuel through approximately 8,500 outlets in 49 states. The majority of these sites utilize the *Phillips 66*, *Conoco* or *76* brands.

Wholesale

At December 31, 2009, our wholesale operations utilized a network of marketers operating approximately 7,680 outlets that provided refined product offtake from our refineries. A strong emphasis is placed on the wholesale channel of trade because of its lower capital requirements. We also buy and sell petroleum products in the spot market. Our refined products are marketed on both a branded and unbranded basis.

In addition to automotive gasoline and diesel, we produce and market aviation gasoline, which is used by smaller, piston engine aircraft. At December 31, 2009, aviation gasoline and jet fuel were sold through independent marketers at approximately 710 *Phillips 66*-branded locations in the United States.

Retail

At December 31, 2009, CFJ Properties, our 50/50 joint venture with Flying J, owned and operated approximately 110 *Flying J*-branded truck travel plazas. Flying J filed for Chapter 11 bankruptcy protection in December 2008. In July 2009, Flying J and Pilot Travel Centers LLC (Pilot) announced a planned merger of their retail businesses, which was approved by the bankruptcy court in January 2010, and is currently under governmental antitrust review. Subject to the closing of the Flying J/Pilot merger and other customary conditions, we have agreed to sell our interest in CFJ to Pilot.

In December 2006, we announced our U.S. company-owned and company-operated retail outlets and our U.S. company-owned and dealer-operated retail outlets would be divested to new or existing wholesale marketers. Of the approximately 830 sites included in the held for sale plans, approximately 100 dealer-operated sites remain to be sold in 2010.

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Transportation

We distribute refined products to our customers via company-owned and common-carrier pipeline, barge, railcar and truck.

Pipelines and Terminals

At December 31, 2009, R&M managed approximately 30,000 miles of common-carrier crude oil, raw natural gas liquids, and petroleum products pipeline systems in the United States, including those partially owned or operated by affiliates. We also owned or operated 44 finished product terminals, seven liquefied petroleum gas terminals, five crude oil terminals and one coke exporting facility.

In December 2007, we acquired a 50 percent equity interest in four Keystone Pipeline entities, to create a joint venture with TransCanada Corporation. In 2008 we exercised an option to reduce our equity interest through a dilution mechanism, which gradually lowered our ownership interest to 20.01 percent by the third quarter of 2009. In the third quarter of 2009, we sold our remaining ownership interest in Keystone.

Tankers

At December 31, 2009, we had 21 double-hulled crude oil tankers under charter, with capacities ranging in size from 713,000 to 2,100,000 barrels. These tankers are used primarily to transport feedstocks to certain of our U.S. refineries. In addition, we utilitized five double-hulled product tankers to transport our heavy and clean products. The tankers discussed here exclude the operations of the company's subsidiary, Polar Tankers, Inc., which are discussed in the E&P segment, as well as an owned tanker on lease to a third party for use in the North Sea.

Specialty Businesses

We manufacture and sell a variety of specialty products including petroleum cokes, lubes (such as automotive and industrial lubricants), solvents, polypropylene and pipeline flow improvers. Our lubes are marketed under the *Phillips 66*, *Conoco*, *76* and *Kendall* brands. We also manufacture and market high-quality graphite and anode-grade petroleum cokes in the United States and Europe for use in the global steel and aluminum industries.

The company's 50 percent owned Excel Paralubes joint venture owns a hydrocracked lubricant base oil manufacturing plant located adjacent to the Lake Charles Refinery. The facility produces approximately 20,000 barrels per day of high-quality, clear hydrocracked base oils.

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R&M—INTERNATIONAL

Refining

At December 31, 2009, R&M owned or had an interest in five refineries outside the United States.

	Location	Ownership	Net Crude Throughput Capacity (MBD)
Humber	N. Lincolnshire, United Kingdom	100.00%	221
Whitegate	Cork, Ireland	100.00	71
Wilhelmshaven	Wilhelmshaven, Germany	100.00	260
MiRO*	Karlsruhe, Germany	18.75	58
Melaka	Melaka, Malaysia	47.00	61
			671

* *Mineraloelraffinerie Oberrhein GmbH.*

Primary crude oil characteristics and sources of crude oil for our international refineries are as follows:

	Characteristics				Sources	
	Sweet	Medium Sour	Heavy Sour	High TAN*	Europe & FSU**	Middle East & Africa
Humber	•	•		•	•	
Whitegate	•				•	•
Wilhelmshaven	•				•	•
MiRO	•		•		•	•
Melaka	•	•	•	•		•

* *High TAN (Total Acid Number): acid content greater than or equal to 1.0 milligram of potassium hydroxide (KOH) per gram.*

** *Former Soviet Union.*

Capacities for and yields of clean products, as well as other products produced, relating to our international refineries are as follows:

	Clean Product Capacity (MBD)			Other Refined Product Output			
	Gasolines	Distillates	Clean Product Yield Capability	Fuel Oil & Other Heavy Intermediates	Natural Gas Liquids	Petroleum Coke	Asphalt
Humber	84	112	84%	•	•	•*	
Whitegate	15	30	65	•			
Wilhelmshaven	36	102	53	•			
MiRO	25	26	85	•	•	•	•
Melaka	14	36	85	•	•	•	•

* *Includes specialty coke.*

We operate a crude oil and products storage complex consisting of 7.5 million barrels of storage capacity and an offshore mooring buoy, located about 80 miles southwest of the Whitegate Refinery in Bantry Bay, Ireland.

In November 2009, we announced a delay in the planned upgrade of the Wilhelmshaven Refinery. During 2010, we expect to complete procurement of long lead items in anticipation of project commencement in 2012, contingent upon market conditions.

The project to expand the crude oil, conversion and treating unit capacity of the Melaka Refinery is expected to be completed by the fourth quarter of 2010. When complete, our net share of the refinery's crude throughput capacity will increase from 61,000 to 80,000 barrels per day.

In 2006, we signed a Memorandum of Understanding with Saudi Aramco to conduct a detailed evaluation of the proposed development of a 400,000 barrel-per-day, full-conversion refinery in Yanbu, Saudi Arabia. The refinery would be designed to process Arabian heavy crude oil and produce high-quality, ultra-low-sulfur refined products. Final investment decision on this project is estimated to occur in 2010.

Marketing

At December 31, 2009, R&M had marketing operations in five European countries. Our European marketing strategy is to sell primarily through owned, leased or joint venture retail sites using a low-cost, high-volume strategy. We use the *JET* brand name to market retail and wholesale products in Austria, Germany and the United Kingdom. In addition, a joint venture in which we have an equity interest markets products in Switzerland under the *Coop* brand name. We also market aviation fuels, liquid petroleum gases, heating oils, transportation fuels and marine bunkers to commercial customers and into the bulk or spot market in the aforementioned countries and Ireland.

As of December 31, 2009, we had approximately 1,225 marketing outlets in our European operations, of which approximately 880 were company-owned and 345 were dealer-owned. Through our joint venture operations in Switzerland, we also have interests in 225 additional sites.

LUKOIL INVESTMENT

At December 31, 2009, our LUKOIL Investment segment represented 4 percent of ConocoPhillips' total assets. In 2004, we became a strategic equity investor in OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. Under the Shareholder Agreement between the two companies, we have representation on the LUKOIL Board of Directors, and LUKOIL's corporate charter requires unanimous Board consent for certain key decisions. At year-end 2009, we had a 20 percent ownership interest in LUKOIL based on authorized and issued shares. Based on estimated shares outstanding at year end, our ownership was 20.09 percent. We use the equity method of accounting for our investment in LUKOIL. See Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

As reported in LUKOIL's publicly available 2008 annual report, the majority of its 2008 upstream oil production was sourced within Russia, with 59 percent from the western Siberia Region, 18 percent from the Timan-Pechora Province and 12 percent from the Urals Region. Outside of Russia, LUKOIL had 2008 oil production in Kazakhstan, Uzbekistan, Egypt and Azerbaijan, and gas production in Uzbekistan, Azerbaijan and Kazakhstan. Seventy-five percent of LUKOIL's natural gas production was sourced within Russia. In addition, LUKOIL has an active exploration program primarily focused in Russia, with additional activity in several countries. Downstream, LUKOIL has seven refineries, as well as a 49 percent interest in the ISAB refinery complex in Italy, resulting in total net crude oil throughput capacity of approximately 1.3 million barrels per day. In 2009, LUKOIL acquired a 45 percent interest in a Dutch refinery. LUKOIL also has a marketing network extending to 25 countries, with the majority of wholesale and retail sales in Russia, the United States and Europe.

CHEMICALS

At December 31, 2009, our Chemicals segment represented 2 percent of ConocoPhillips' total assets. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem), a joint venture with Chevron Corporation, headquartered in The Woodlands, Texas.

CPChem's business is structured around two primary operating segments: Olefins & Polyolefins and Specialties, Aromatics & Styrenics. The Olefins & Polyolefins segment produces and markets ethylene, propylene, and other olefin products, which are primarily consumed within CPChem for the production of polyethylene, normal alpha olefins, polypropylene and polyethylene pipe. The Specialties, Aromatics & Styrenics segment manufactures and markets aromatics products, such as benzene, styrene, paraxylene and cyclohexane. This segment also manufactures and markets polystyrene, as well as styrene-butadiene copolymers. Furthermore, this segment manufactures and markets a variety of specialty chemical products including organosulfur chemicals, solvents, catalysts, drilling chemicals, mining chemicals and high-performance engineering plastics and compounds.

CPChem's manufacturing facilities are located in Belgium, Brazil, China, Colombia, Qatar, Saudi Arabia, Singapore, South Korea and the United States.

CPChem owns a 49 percent interest in Qatar Chemical Company Ltd. (Q-Chem), a joint venture that owns a major olefins and polyolefins complex in Mesaieed, Qatar. CPChem also owns a 49 percent interest in Qatar Chemical Company II Ltd. (Q-Chem II), a joint venture that began construction of a second complex in Mesaieed in 2005. This Q-Chem II facility is designed to produce polyethylene and normal alpha olefins on a site adjacent to the Q-Chem complex. In connection with this project, CPChem entered into a separate agreement establishing a joint venture to develop an ethylene cracker in Ras Laffan Industrial City, Qatar. Operational startup of the Q-Chem II project is anticipated in the second half of 2010.

In 2008, Jubail Chevron Phillips Company, a 50 percent owned joint venture of CPChem, commenced startup of an integrated styrene facility in Al Jubail, Saudi Arabia. The facility was built adjacent to the existing aromatics complex owned by Saudi Chevron Phillips Company (SCP), another 50 percent owned CPChem joint venture. Project completion was achieved in July 2009.

In 2007, CPChem formed a 50 percent owned joint venture, Saudi Polymers Company (SPCo), to construct and operate an integrated petrochemicals complex at Al Jubail, Saudi Arabia. Construction began in January 2008, and commercial production is scheduled to begin in late 2011. In July 2009, an initial public offering of shares in CPChem's joint venture partner's company was completed, resulting in a corresponding increase in the partner's ownership interest in SPCo, which reduced CPChem's ownership to 35 percent.

EMERGING BUSINESSES

At December 31, 2009, our Emerging Businesses segment represented 1 percent of ConocoPhillips' total assets. The segment encompasses the development of new technologies and businesses outside our normal operations. Activities within this segment are focused on power generation and new technologies related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment.

The focus of our power business is on developing projects to support our E&P and R&M strategies. While projects primarily in place to enable these strategies are included within their respective segments, projects with a significant merchant component are included in the Emerging Businesses segment.

The Immingham combined heat and power plant (CHP), a wholly owned 730-megawatt facility in the United Kingdom, provides steam and electricity to the Humber Refinery and steam to a neighboring refinery, as well as merchant power into the U.K. market. In December 2009, commercial operation began on a 450-megawatt expansion, bringing total capacity to 1,180 megawatts.

We also own a gas-fired cogeneration plant in Orange, Texas, as well as a 50 percent operating interest in Sweeny Cogeneration LP, a joint venture near the Sweeny Refinery complex.

Our Technology group focuses on developing new business opportunities designed to provide future growth prospects for ConocoPhillips. Focus areas include advanced hydrocarbon processes, energy efficiency technologies, new petroleum-based products, renewable fuels and carbon capture and conversion technologies. We have commercialized production of renewable diesel, a new type of renewable fuel that utilizes existing infrastructure. Relationships with Iowa State University, Colorado Center for Biorefining and Biofuels, and Archer Daniels Midland to develop second-generation biofuels have also been initiated. In addition, we have formed an internal group to evaluate wind, solar and geothermal investment opportunities.

Our technology center in Qatar, which we developed with General Electric Company to research water sustainability solutions for petroleum, petrochemical, municipal and agricultural applications, opened in 2009.

We offer a gasification technology (E-Gas™) that uses petroleum coke, coal, and other low-value hydrocarbons as feedstock, resulting in high-value synthesis gas used for a slate of products, including power, substitute natural gas (SNG), hydrogen and chemicals. This clean, efficient technology facilitates carbon capture and storage as well as minimizes criteria pollutant emissions and reduces water consumption. E-Gas™ Technology has been utilized in commercial applications since 1987 and is currently licensed to several third parties. We are currently pursuing three projects that apply the E-Gas™ Technology, two in the United States and one in the United Kingdom. We are also pursuing several additional licensing opportunities, primarily in Asia and North America.

COMPETITION

We compete with private, public and state-owned companies in all facets of the petroleum and chemicals businesses. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive. No single competitor, or small group of competitors, dominates any of our business lines.

Upstream, our E&P segment competes with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil and natural gas in an efficient, cost-effective manner. Based on publicly available year-end 2008 reserves statistics, we had the seventh-largest total of worldwide proved reserves of nongovernment-controlled companies. We deliver our oil and natural gas production into the worldwide oil and natural gas commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and operating efficient oil and gas producing properties.

The Midstream segment, through our equity investment in DCP Midstream and our consolidated operations, competes with numerous other integrated petroleum companies, as well as natural gas transmission and distribution companies, to deliver components of natural gas to end users in the commodity natural gas markets. DCP Midstream is a large producer of natural gas liquids in the United States. Principal methods of competing include economically securing the right to purchase raw natural gas into gathering systems, managing the pressure of those systems, operating efficient natural gas liquids processing plants and securing markets for the products produced.

Downstream, our R&M segment competes primarily in the United States, Europe and the Asia Pacific Region. Based on the statistics published in the December 21, 2009, issue of the *Oil & Gas Journal*, our R&M segment had the largest U.S. refining capacity of 17 large refiners of petroleum products. Worldwide, our refining capacity ranked fourth among nongovernment-controlled companies. In the Chemicals segment, CPChem generally ranked within the top 10 producers of many of its major product lines, based on average 2009 production capacity, as published by industry sources. Petroleum products, petrochemicals and plastics are delivered into the worldwide commodity markets. Elements of competition for both our R&M and Chemicals segments include product improvement, new product development, low-cost structures, and efficient manufacturing and distribution systems. In the marketing portion of the business, competitive factors include product properties and processibility, reliability of supply, customer service, price and credit terms, advertising and sales promotion, and development of customer loyalty to ConocoPhillips' or CPChem's branded products.

GENERAL

At the end of 2009, we held a total of 1,435 active patents in 72 countries worldwide, including 565 active U.S. patents. During 2009, we received 30 patents in the United States and 59 foreign patents. Our products and processes generated licensing revenues of $14 million in 2009. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $190 million, $209 million, and $160 million in 2009, 2008 and 2007, respectively.

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure consistent health, safety and environmental excellence. In support of the goal of zero incidents, we have implemented an HSE Excellence process, which enables business units to measure their performance and compliance with our HSE Management System requirements, identify gaps, and develop improvement plans. Assessments are conducted annually to capture progress and set new targets. We are also committed to continuously improving process safety and preventing releases of hazardous materials.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 58 through 61 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2009 and those expected for 2010 and 2011.

Web Site Access to SEC Reports

Our Internet Web site address is *http://www.conocophillips.com*. Information contained on our Internet Web site is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our Web site, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC's Web site at *http://www.sec.gov*.

Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices and refining margins.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas, natural gas liquids and refined products. The factors influencing the prices of crude oil, natural gas, natural gas liquids and refined products are beyond our control. Lower crude oil, natural gas, natural gas liquids and refined products prices may reduce the amount of these commodities we can produce economically, which may have a material adverse effect on our revenues, operating income and cash flows.

Unless we successfully add to our existing proved reserves, our future crude oil and natural gas production will decline, resulting in an adverse impact to our business.

The rate of production from crude oil and natural gas properties generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, or, through engineering studies, identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil and natural gas. Accordingly, to the extent we are unsuccessful in replacing the crude oil and natural gas we produce with good prospects for future production, our business will experience reduced cash flows and results of operations.

Any material change in the factors and assumptions underlying our estimates of crude oil and natural gas reserves could impair the quantity and value of those reserves.

Our proved crude oil and natural gas reserve information included in this annual report has been derived from engineering estimates prepared or reviewed by our personnel. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil and natural gas that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported.

We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations. Likewise, future environmental laws and regulations may impact or limit our current business plans and reduce demand for our products.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- Emissions into the atmosphere (such as nitrogen oxides, sulfur dioxide and mercury emissions, and greenhouse gas emissions as they are, or may become, regulated).
- The handling, use, storage, transportation, disposal and clean up of hazardous materials and hazardous and nonhazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

In addition, our business operations are designed and operated to accommodate expected climatic conditions. To the extent there are significant changes in the Earth's climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall.

Domestic and worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Actions of the U.S., state and local governments through tax and other legislation, executive order and commercial restrictions could reduce our operating profitability both in the United States and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by both the United States and host governments have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 67 percent of our hydrocarbon production in 2009 was derived from production outside the United States, and 64 percent of our proved reserves, as of December 31, 2009, were located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations.

Changes in governmental regulations may impose price controls and limitations on production of crude oil and natural gas.

Our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil and natural gas wells below actual production capacity in order to conserve supplies of crude oil and natural gas. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

Our investments in joint ventures decrease our ability to manage risk.

We conduct many of our operations through joint ventures in which we may share control with our joint venture participants. There is a risk that our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or that our joint venture participants may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint venture interest, to adequately manage the risks associated with any acquisitions or joint ventures could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

Our operations present hazards and risks that require significant and continuous oversight.

The scope and nature of our operations present a variety of operational hazards and risks that must be managed through continual oversight and control. These risks are present throughout the process of extraction, transportation, refinement and storage of the hydrocarbons we produce. Failure to manage these risks could result in injury or loss of life, environmental damage, loss of revenues and damage to our reputation.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2009, as well as matters previously reported in our 2008 Form 10-K and our first-, second- and third-quarter 2009 Form 10-Qs that were not resolved prior to the fourth quarter of 2009. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings was decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to the U.S. Securities and Exchange Commission's (SEC) regulations.

Our U.S. refineries are implementing two separate consent decrees, regarding alleged violations of the Federal Clean Air Act, with the U.S. Environmental Protection Agency (EPA), six states and one local air pollution agency. Some of the requirements and limitations contained in the decrees provide for stipulated penalties for violations. Stipulated penalties under the decrees are not automatic, but must be requested by one of the agency signatories. As part of periodic reports under the decrees or other reports required by permits or regulations, we occasionally report matters that could be subject to a request for stipulated penalties. If a specific request for stipulated penalties meeting the reporting threshold set forth in SEC rules is made pursuant to these decrees based on a given reported exceedance, we will separately report that matter and the amount of the proposed penalty.

New Matters
In May 2008, the EPA issued a Compliance Order to ConocoPhillips alleging our Argenta and Sunnyside Compressor Station facilities in Colorado violated provisions of the Clean Air Act and failed to comply with several permit conditions. On February 5, 2010, we settled this matter for a payment of $175,000 and agreement to install certain emission control equipment.

In 2009, ConocoPhillips notified the EPA and the U.S. Department of Justice (DOJ) that it had self-identified certain compliance issues related to Benzene Waste Operations National Emission Standard for Hazardous Air Pollutants requirements at its Trainer, Pennsylvania, and Borger, Texas, facilities. On January 6, 2010, the DOJ provided its initial penalty demand for this matter as part of our confidential settlement negotiations. We continue to work with the DOJ to resolve this matter.

On December 17, 2009, the San Francisco Regional Water Quality Control Board's enforcement staff (SFRWQCB) issued an Administrative Civil Liability Complaint alleging 18 exceedances of the Rodeo facility's stormwater permit that occurred during 2008 and 2009. The Complaint seeks a penalty of $490,000. We are working with the SFRWQCB to resolve this matter.

On January 22, 2010, the Bay Area Air Quality Management District (BAAQMD) issued a settlement demand to resolve 16 Notices of Violation (NOVs) issued in 2008 and 2009 that allege violations of air pollution control regulations and/or facility permit conditions at the Rodeo facility. The amount of the settlement demand is $179,000. We are working with BAAQMD to resolve this matter.

Matters Previously Reported
ConocoPhillips Pipe Line Company (CPPL) received a Notice of Probable Violation and Proposed Civil Penalty (NOPV) from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (DOT) dated March 30, 2009. The NOPV alleges that CPPL violated certain operation and

safety regulations regarding the control room response to a release on January 8, 2008, near Denver City, Texas. DOT's proposed penalty for the alleged violation is $200,000. We are working with DOT to resolve this matter.

On October 23, 2008, ConocoPhillips received a demand from the Los Angeles Regional Water Quality Control Board (LARWQCB) to settle multiple alleged exceedances of National Pollutant Discharge Elimination System permit effluent limits at its Los Angeles lubricants plant dating back to 2000. We paid a negotiated settlement of $150,000 to the LARWQCB on January 25, 2010, to resolve this matter.

In October 2003, the District Attorney's Office in Sacramento, California, filed a complaint in Superior Court for alleged methyl tertiary-butyl ether (MTBE) contamination in groundwater. On April 4, 2008, the District Attorney's Office filed an amended complaint that included alleged violations of state regulations relating to operation or maintenance of underground storage tanks. There are numerous defendants named in the suit in addition to ConocoPhillips. We intend to continue to contest this lawsuit.

In October 2007, we received a Complaint from the EPA alleging violations of the Clean Water Act related to a 2006 oil spill at our Bayway Refinery and proposing a penalty of $156,000. We are working with the EPA and the U.S. Coast Guard to resolve this matter.

In March 2005, CPPL received an NOPV from DOT alleging violation of DOT operation and safety regulations at certain facilities in Kansas, Missouri, Illinois, Indiana, Wyoming and Nebraska. DOT is proposing penalties in the amount of $184,500. An information hearing was held on September 24, 2007. CPPL has provided additional information in support of its position. We are currently awaiting a ruling from DOT.

In 2006, Polar Tankers, Inc. and ConocoPhillips resolved and agreed to pay, with no admission of liability, civil penalties and response costs associated with a 2004 oil spill in Puget Sound. We remain in negotiations with the natural resource trustees regarding the natural resource damage assessment to better the environment.

In April 2004, in response to several historical spills at the Albuquerque Products Terminal, we received an Administrative Compliance Order from the New Mexico Environment Department. The order does not propose a penalty assessment, but rather attempts to impose specific design, construction and operational changes. ConocoPhillips transferred its interest in the terminal, and the current owner has ceased operations. The spills have been remediated in compliance with New Mexico Environmental Department standards. ConocoPhillips has withdrawn its settlement offer and requested that this Order be dismissed.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
John A. Carrig	President and Chief Operating Officer	58
W. C. W. Chiang	Senior Vice President, Refining, Marketing and Transportation	49
Sigmund L. Cornelius	Senior Vice President, Finance, and Chief Financial Officer	55
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	52
Ryan M. Lance	Senior Vice President, Exploration and Production – International	47
Kevin O. Meyers	Senior Vice President, Exploration and Production – Americas	56
James J. Mulva	Chairman of the Board of Directors and Chief Executive Officer	63
Glenda M. Schwarz	Vice President and Controller	44
Jeff W. Sheets	Senior Vice President, Planning and Strategy	52

* *On February 15, 2010.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 12, 2010. Set forth below is information about the executive officers.

John A. Carrig was appointed President and Chief Operating Officer in October 2008, having previously served as Executive Vice President, Finance, and Chief Financial Officer since the merger of Conoco and Phillips in 2002 (the merger).

W. C. W. Chiang was appointed Senior Vice President, Refining, Marketing and Transportation in October 2008. He previously served as Senior Vice President, Commercial since 2007. Prior to that, he served as President, Americas Supply & Trading, Commercial, from 2005 through 2007 and as President, Downstream Strategy, Integration and Specialty Businesses from 2003 through 2005.

Sigmund L. Cornelius was appointed Senior Vice President, Finance, and Chief Financial Officer in October 2008. Prior to that, he served as Senior Vice President, Planning, Strategy and Corporate Affairs since September 2007, having previously served as President, Exploration and Production—Lower 48 since 2006 and President, Global Gas since 2004.

Janet L. Kelly was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary effective September 1, 2007, having previously served as Deputy General Counsel since 2006. Prior to joining ConocoPhillips in 2006, she was a partner at Zelle, Hoffman, Voelbel, Mason and Gette during 2005 and 2006.

Ryan M. Lance was appointed Senior Vice President, Exploration and Production — International, in May 2009. Prior to that, he served as President, Exploration and Production — Asia, Africa, Middle East and Russia/Caspian since April 2009, having previously served as President, Exploration and Production— Europe, Asia, Africa and the Middle East since September 2007. He served as Senior Vice President, Technology since February 2007, and prior to that served as Senior Vice President, Technology and Major Projects since 2006. He served as President, Downstream Strategy, Integration and Specialty Businesses since 2005.

Kevin O. Meyers was appointed Senior Vice President, Exploration and Production — Americas, in May 2009, having previously served as President, Canada, Exploration & Production, since 2006. He served as President, ConocoPhillips Russia & Caspian Region, from 2004 to 2006.

James J. Mulva has served as Chairman of the Board of Directors and Chief Executive Officer since October 2008, having previously served as Chairman of the Board of Directors, President and Chief Executive Officer since October 2004. Prior to that, he served as President and Chief Executive Officer since the merger.

Glenda M. Schwarz was appointed Vice President and Controller in April 2009. She previously served as General Auditor and Chief Ethics Officer since 2008, having previously served as General Manager, Downstream Finance and Performance Analysis since 2005, and prior to that served as Assistant Controller, External Reporting and Accounting Policy since 2004.

Jeff W. Sheets was appointed Senior Vice President, Planning and Strategy in October 2008, having previously served as Vice President and Treasurer since the merger.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Quarterly Common Stock Prices and Cash Dividends Per Share

ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbol "COP."

	Stock Price		
	High	Low	Dividends
2009			
First	**$ 57.44**	**34.12**	**.47**
Second	**48.71**	**37.52**	**.47**
Third	**47.30**	**38.62**	**.47**
Fourth	**54.13**	**44.88**	**.50**
2008			
First	$ 89.71	67.85	.47
Second	95.96	75.52	.47
Third	94.65	67.31	.47
Fourth	72.25	41.27	.47

Closing Stock Price at December 31, 2009	$ 51.07
Closing Stock Price at January 31, 2010	$ 48.00
Number of Stockholders of Record at January 31, 2010*	61,039

* *In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency or listing.*

Issuer Purchases of Equity Securities

				Millions of Dollars
Period	Total Number of Shares Purchased *	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2009	157,478	$ 50.72	—	—
November 1-30, 2009	17,369	51.98	—	—
December 1-31, 2009	3,324	50.75	—	—
Total	178,171	$ 50.85	—	

* *Represents the repurchase of common shares from company employees in connection with the company's broad-based employee incentive plans.*

Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2009	2008	2007	2006	2005
Sales and other operating revenues	**$ 149,341**	240,842	187,437	183,650	179,442
Income (loss) from continuing operations	**4,936**	(16,928)	11,978	15,626	13,673
Income (loss) from continuing operations attributable to ConocoPhillips	**4,858**	(16,998)	11,891	15,550	13,640
Per common share					
Basic	**3.26**	(11.16)	7.32	9.80	9.79
Diluted	**3.24**	(11.16)	7.22	9.66	9.63
Net income (loss)	**4,936**	(16,928)	11,978	15,626	13,562
Net income (loss) attributable to ConocoPhillips	**4,858**	(16,998)	11,891	15,550	13,529
Per common share					
Basic	**3.26**	(11.16)	7.32	9.80	9.71
Diluted	**3.24**	(11.16)	7.22	9.66	9.55
Total assets	**152,588**	142,865	177,757	164,781	106,999
Long-term debt	**26,925**	27,085	20,289	23,091	10,758
Joint venture acquisition obligation—long-term	**5,009**	5,669	6,294	—	—
Cash dividends declared per common share	**1.91**	1.88	1.64	1.44	1.18

See Management’s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance an understanding of this data.

The financial data for 2008 includes the impact of impairments relating to goodwill and to our LUKOIL investment that together amount to $32,853 million before- and after-tax. For additional information, see the “Goodwill Impairment” section of Note 9—Goodwill and Intangibles and the “LUKOIL” section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

The financial data for 2007 includes the impact of a $4,588 million before-tax ($4,512 million after-tax) impairment related to the expropriation of our oil interests in Venezuela. For additional information, see the “Expropriated Assets” section of Note 10—Impairments, in the Notes to Consolidated Financial Statements.

Additionally, the acquisition of Burlington Resources in 2006 affects the comparability of the amounts included in the table above.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

February 25, 2010

Management's Discussion and Analysis is the company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "forecast," "intend," "believe," "expect," "plan," "schedule," "target," "should," "goal," "may," "anticipate," "estimate" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 66.

The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to net income (loss) attributable to ConocoPhillips.

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is an international, integrated energy company. We are the third-largest integrated energy company in the United States, based on market capitalization. We have approximately 30,000 employees worldwide, and at year-end 2009 had assets of $153 billion. Our stock is listed on the New York Stock Exchange under the symbol "COP."

Our business is organized into six operating segments:

- **Exploration and Production (E&P)**—This segment primarily explores for, produces, transports and markets crude oil, natural gas, natural gas liquids and bitumen on a worldwide basis.
- **Midstream**—This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.
- **Refining and Marketing (R&M)**—This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia.
- **LUKOIL Investment**—This segment consists of our equity investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2009, our ownership interest was 20 percent based on issued shares and 20.09 percent based on estimated shares outstanding.
- **Chemicals**—This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem).
- **Emerging Businesses**—This segment represents our investment in new technologies or businesses outside our normal scope of operations.

The business environment for the energy industry in 2009 continued to experience volatility associated with the supply/demand factors that drive its commodity prices and margins. During 2008, forecasts of worldwide economic growth and increasingly scarce supply, a weakening U.S. dollar, and other factors helped drive crude oil prices to record highs by mid-year, with the benchmark West Texas Intermediate (WTI) peaking at almost $150 per barrel. This was followed by an abrupt shift into a severe global financial recession, which drove crude oil prices to the low-$30-per-barrel range by the end of 2008. As the global economy began to recover, oil prices steadily improved during 2009 and have remained fairly strong due to demand in Asia. The recovery from the recession in the United States, however, has been slower and has impacted demand for U.S. natural gas and refined products.

In response to this challenging business environment, ConocoPhillips announced several strategic initiatives in late 2009 designed to improve its financial position and increase returns on capital. This will be accomplished primarily through a combination of enhanced capital discipline and asset portfolio rationalization, consistent with our objectives of creating shareholder value and improving financial flexibility, while pursuing long-term strategic projects. Our total capital program in 2010 is expected to be $11.2 billion, down from a budgeted $12.5 billion in 2009. To improve our financial position and strengthen the balance sheet, we intend to raise approximately $10 billion from asset dispositions over the next two years. Proceeds will be targeted to debt reduction, accelerating the return to our targeted debt-to-capital ratio of 20 percent to 25 percent. After these initiatives, we intend to continue to replace reserves and increase production from a reduced, but more strategic, asset base.

Crude oil and natural gas prices, along with refining margins, are the most significant factors in our profitability, and are driven by market factors over which we have no control. As noted above, these prices and margins are subject to extreme volatility. However, from a competitive perspective, there are other important factors we must manage well to be successful, including:

- Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner. Safety is our first priority, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. Optimizing utilization rates at our refineries and minimizing downtime in producing fields enable us to capture the value available in the market in terms of prices and margins. During 2009, our worldwide refining capacity utilization rate was 84 percent, compared with 90 percent in 2008. The lower rate primarily reflects reduced throughput at our U.S. and German refineries due to economic conditions, as well as higher planned downtime, efficiently utilizing periods of lower margins for maintenance. Although certain North America production was shut-in during part of 2009 due to the natural gas pricing environment, we increased total production on a barrel-of-oil-equivalent basis in 2009 by 2 percent. Finally, we strive to conduct our operations in a manner consistent with our environmental stewardship principles.
- Adding to our proved reserve base. We primarily add to our proved reserve base in three ways:
  - Successful exploration and development of new fields.
  - Acquisition of existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.

  Through a combination of the methods listed above, we have been successful in the past in maintaining or adding to our production and proved reserve base, and we anticipate being able to do so in the future. In the five years ending December 31, 2009, our reserve replacement was 145 percent. Over this period we added reserves through acquisitions and project developments, partially offset by the impact of asset expropriations in Venezuela and Ecuador.

  Access to additional resources has become increasingly difficult as direct investment is prohibited in some nations, while fiscal and other terms in other countries can make projects uneconomic or unattractive. In addition, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

- Controlling costs and expenses. Since we cannot control the prices of the commodity products we sell, controlling operating and overhead costs, within the context of our commitment to safety and environmental stewardship, are high priorities. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Because managing operating and overhead costs is critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs. Operating and overhead costs were reduced 13 percent in 2009, compared with 2008, reflecting both market conditions and our continued emphasis on cost control throughout the year.
- Selecting the appropriate projects in which to invest our capital dollars. We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns.

  The capital expenditures and investments portion of our capital program totaled $10.9 billion in 2009, and we anticipate capital expenditures and investments to be approximately $10.5 billion in 2010. The 2010 budget is consistent with our recently announced plan to improve returns through increased capital discipline, while still funding existing projects and enabling us to preserve flexibility to develop major projects in the future. In addition to our capital program, we paid dividends on our common stock of $2.8 billion in 2009.
- Managing our asset portfolio. We continually evaluate our assets to determine whether they no longer fit our strategic plans and should be sold or otherwise disposed. In 2008, we sold our retail marketing assets in Norway, Sweden and Denmark, in addition to our E&P properties in Argentina and the Netherlands. In 2009, we sold a majority of our U.S. retail marketing assets. Also in 2009, we announced our intention to raise approximately $10 billion from asset dispositions over the next two years.
- Developing and retaining a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. Throughout the company, we focus on the continued learning, development and technical training of our employees. Professional new hires participate in structured development programs designed to accelerate their technical and functional skills.

Our key performance indicators are shown in the statistical tables provided at the beginning of the operating segment sections that follow. These include crude oil and natural gas liquids prices, natural gas prices, production, refining capacity utilization, and refinery output.

Other significant factors that can affect our profitability include:

- Impairments. As mentioned above, we participate in capital-intensive industries. At times, our investments become impaired when our reserve estimates are revised downward, when crude oil prices, natural gas prices or refining margins decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to its fair market value. We may also invest large amounts of money in exploration blocks which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. Before-tax impairments in 2009 totaled $0.8 billion and primarily related to certain natural gas properties in western Canada and our equity investment in Naraynmarneftegaz (NMNG). Before-tax impairments in 2008, excluding the goodwill impairment discussed below and a $7.4 billion impairment related to our LUKOIL investment, totaled $1.7 billion.

- Goodwill. At year-end 2009 and 2008, we had $3.6 billion and $3.8 billion, respectively, of goodwill on our balance sheet, compared with $29.3 billion at year-end 2007. In 2008, we recorded a $25.4 billion complete impairment of our E&P segment goodwill, primarily as a function of decreased year-end commodity prices and the decline in our market capitalization. For additional information, see Note 9—Goodwill and Intangibles, in the Notes to Consolidated Financial Statements. Deterioration of market conditions in the future could lead to other goodwill impairments that may have a substantial negative, though noncash, effect on our profitability.

- Effective tax rate. Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the “mix” of pretax earnings within our global operations.

- Fiscal and regulatory environment. As commodity prices and refining margins fluctuated upward over the last several years, certain governments responded with changes to their fiscal take. These changes have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. In June 2007, our Venezuelan oil projects were expropriated, and we recorded a $4.5 billion after-tax impairment. In the second quarter of 2009, our assets in Ecuador were effectively expropriated, and we recorded a $51 million before- and after-tax impairment (see the “Expropriated Assets” section of Note 10—Impairments, in the Notes to Consolidated Financial Statements). We were also negatively impacted by increased production taxes enacted by the state of Alaska in the fourth quarter of 2007. In Canada, the Alberta provincial government changed the royalty structure for Crown lands, effective January 1, 2009, so that a component of the new royalty rate is tied to prevailing prices. In October 2008, we and our co-venturers signed definitive agreements for the proportional dilution of our equity interests in the Republic of Kazakhstan’s North Caspian Sea Production Sharing Agreement, which includes the Kashagan Field, to allow the state-owned energy company to increase its ownership percentage effective January 1, 2008. Partially offsetting the above fiscal take increases were lower corporate income tax rates enacted by Canada and Germany during 2007. These tax rate reductions applied to all corporations and were not exclusive to the oil and gas industry.

Segment Analysis

The E&P segment's results are most closely linked to crude oil and natural gas prices. These are commodity products, the prices of which are subject to factors external to our company and over which we have no control. Industry crude oil prices for West Texas Intermediate were lower in 2009, compared with 2008, averaging $61.69 per barrel in 2009, a decrease of 38 percent. Crude oil prices steadily trended upward during 2009, as global crude inventories were reduced due to lower production and economic recovery that stimulated the resumption of global oil demand growth. Industry natural gas prices for Henry Hub decreased 56 percent during 2009 to an average price of $3.99 per million British thermal units, primarily as a result of lower demand due to the U.S. recession and higher domestic production due to increased shale gas production.

The Midstream segment's results are most closely linked to natural gas liquids prices. The most important factor affecting the profitability of this segment is the results from our 50 percent equity investment in DCP Midstream. DCP Midstream's natural gas liquids prices decreased 43 percent in 2009.

Refining margins, refinery utilization, cost control and marketing margins primarily drive the R&M segment's results. Refining margins are subject to movements in the cost of crude oil and other feedstocks, and the sales prices for refined products, both of which are subject to market factors over which we have no control. Global refining margins remained weak in 2009. The U.S. benchmark 3:2:1 crack spread decreased almost 20 percent in 2009, while the N.W. Europe benchmark declined 54 percent. Demand, particularly for distillates, continued to be suppressed by the global economic slowdown. In addition, the compressed differential in prices for high-quality crude oil, compared with those of lower-quality crude oil, reduced margins for those refineries configured to capitalize on the ability to process lower-quality crudes.

The LUKOIL Investment segment consists of our investment in the ordinary shares of LUKOIL. At December 31, 2009, our ownership interest in LUKOIL was 20 percent based on issued shares and 20.09 percent based on estimated shares outstanding. LUKOIL's results are subject to factors similar to those of our E&P and R&M segments. LUKOIL's upstream results are closely linked to Russian (Urals) crude oil prices and are heavily impacted by extraction tax rates. Refining margins are significant factors on LUKOIL's downstream results. Export tariff rates for crude oil and refined products also have a significant impact on both upstream and downstream results.

The Chemicals segment consists of our 50 percent interest in CPChem. The chemicals and plastics industry is mainly a commodity-based industry where the margins for key products are based on market factors over which CPChem has little or no control. CPChem is investing in feedstock-advantaged areas in the Middle East with access to large, growing markets, such as Asia.

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment. Some of these technologies have the potential to become important drivers of profitability in future years.

RESULTS OF OPERATIONS

Consolidated Results

A summary of the company's net income (loss) attributable to ConocoPhillips by business segment follows:

Years Ended December 31	Millions of Dollars 2009	2008	2007
Exploration and Production (E&P)	$ **3,604**	(13,479)	4,615
Midstream	**313**	541	453
Refining and Marketing (R&M)	**37**	2,322	5,923
LUKOIL Investment	**1,663**	(5,488)	1,818
Chemicals	**248**	110	359
Emerging Businesses	**3**	30	(8)
Corporate and Other	**(1,010)**	(1,034)	(1,269)
Net income (loss) attributable to ConocoPhillips	$ **4,858**	(16,998)	11,891

2009 vs. 2008

The improved results in 2009 were primarily the result of:

- The absence of a $25,443 million before- and after-tax impairment of all E&P segment goodwill in 2008.
- The absence of a $7,410 million before- and after-tax impairment of our LUKOIL investment in 2008.
- Lower production taxes.
- Reduced operating and overhead expenses.

These items were partially offset by:

- Lower crude oil, natural gas and natural gas liquids prices, which impacted our E&P, Midstream and LUKOIL Investment segments.
- Lower refining margins in our R&M segment.

2008 vs. 2007

The lower results in 2008 were primarily the result of:

- The goodwill and LUKOIL impairments, noted above.
- Lower U.S. refining margins in our R&M segment.
- An increase in other asset impairments, predominantly in our E&P and R&M segments.

These items were partially offset by:

- Higher crude oil, natural gas and natural gas liquids prices, which benefitted our E&P, Midstream and LUKOIL Investment segments. Commodity price benefits were somewhat counteracted by increased production taxes.
- A 2007 complete impairment ($4,588 million before-tax, $4,512 million after-tax) of our oil interests in Venezuela, resulting from their expropriation.

Statement of Operations Analysis

2009 vs. 2008

Sales and other operating revenues decreased 38 percent in 2009, while purchased crude oil, natural gas and products decreased 39 percent. These decreases were mainly the result of significantly lower prices for petroleum products, crude oil, natural gas and natural gas liquids.

Equity in earnings of affiliates decreased 30 percent in 2009, primarily due to reduced earnings from DCP Midstream; LUKOIL; Merey Sweeny, L.P. (MSLP); Malaysian Refining Company Sdn. Bhd.; and Excel Paralubes, which were partially offset by higher earnings from Chevron Phillips Chemical Company LLC. The decreases were mainly the result of lower commodity prices and refining margins.

Other income decreased 52 percent during 2009. The decrease was primarily due to 2008 gains related to asset dispositions in our E&P and R&M segments.

Production and operating expenses decreased 13 percent in 2009, as a result of lower utilities costs, favorable foreign exchange impacts, and our cost reduction efforts.

Selling, general and administrative expense decreased 18 percent in 2009, primarily due to disposition of U.S. and international marketing assets.

Taxes other than income taxes decreased 25 percent in 2009, primarily due to lower production taxes resulting from lower crude oil prices, as well as reduced excise taxes on petroleum product sales.

Impairments decreased from $34,539 million in 2008 to $535 million in 2009, primarily reflecting the 2008 goodwill and LUKOIL impairments. Other impairments decreased $1,202 million during 2009. For additional information, see Note 6—Investments, Loans and Long-Term Receivables, Note 9—Goodwill and Intangibles, and Note 10—Impairments, in the Notes to Consolidated Financial Statements.

Interest and debt expense increased 38 percent in 2009, as a result of a higher average debt level, partially offset by lower interest rates. Interest expense also increased as a result of lower capitalized interest.

See Note 20—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax expense and effective tax rate.

2008 vs. 2007

Sales and other operating revenues increased 28 percent in 2008, while purchased crude oil, natural gas and products increased 37 percent. These increases were the result of higher petroleum product prices and higher prices for crude oil, natural gas and natural gas liquids.

Equity in earnings of affiliates decreased 16 percent in 2008, reflecting:

- Lower results from WRB Refining LLC, due to lower margins and a decline in equity ownership in accordance with the designed formation of the venture.
- Lower results from CPChem, due to higher operating costs, lower specialties, aromatics and styrenics margins, and lower olefins and polyolefins volumes.
- The absence of earnings from our heavy oil joint ventures expropriated by Venezuela in 2007.
- Increased losses related to our NMNG joint venture as a result of higher production taxes and increased depreciation, depletion and amortization (DD&A) costs during the startup and early production phase of the Yuzhno Khylchuyu (YK) Field.

These negative results were somewhat offset by improved results from the FCCL Partnership, DCP Midstream, LUKOIL (excluding the investment impairment), and CFJ Properties.

Other income decreased 45 percent during 2008, mainly due to a lower net benefit from asset rationalization efforts, the release in 2007 of escrowed funds associated with our Hamaca joint venture in Venezuela, and the settlement of retroactive adjustments for crude oil quality differentials on Trans-Alaska Pipeline System shipments (Quality Bank) in 2007.

Exploration expenses increased 33 percent during 2008, reflecting increased dry hole costs and higher expenses for post-discovery feasibility and development planning studies.

Impairments increased from $5,030 million in 2007 to $34,539 million in 2008. This increase primarily reflects the 2008 goodwill and LUKOIL impairments, partially offset by a 2007 impairment of $4,588 million related to the expropriation of our oil interests in Venezuela.

Interest and debt expense decreased 25 percent in 2008, primarily due to lower average interest rates, as well as the absence of 2007 interest expense related to the Alaska Quality Bank settlements.

Foreign currency transaction losses incurred during 2008 totaled $117 million, compared with foreign currency transaction gains of $201 million in 2007. This change occurred as the Canadian dollar, Russian rouble, British pound, and euro all weakened against the U.S. dollar during 2008, compared with the strengthening of these currencies against the U.S. dollar in 2007.

See Note 20—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax expense and effective tax rate.

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Segment Results

E&P

	2009	2008	2007
		Millions of Dollars	
Net Income (Loss) Attributable to ConocoPhillips			
Alaska	$ **1,540**	2,315	2,255
Lower 48	**(37)**	2,673	1,993
United States	**1,503**	4,988	4,248
International	**2,101**	6,976	367
Goodwill impairment	**—**	(25,443)	—
	$ **3,604**	(13,479)	4,615

		Dollars Per Unit	
Average Sales Prices			
Crude oil and natural gas liquids (per barrel)			
United States	$ **53.21**	89.38	63.87
International	**57.40**	89.32	68.09
Total consolidated operations	**55.47**	89.35	66.01
Equity affiliates	**58.23**	71.15	48.72
Total E&P	**55.63**	88.91	64.99
Synthetic oil (per barrel)			
International	**62.01**	103.31	74.32
Bitumen (per barrel)			
International	**39.67**	46.85	—
Equity affiliates	**45.69**	58.54	37.94
Total E&P	**44.84**	56.72	37.94
Natural gas (per thousand cubic feet)			
United States	**3.45**	7.67	5.98
International	**4.94**	8.76	6.51
Total consolidated operations	**4.30**	8.28	6.26
Equity affiliates	**2.35**	2.04	.30
Total E&P	**4.26**	8.27	6.26

Average Production Costs Per Barrel of Oil Equivalent			
United States	$ **7.73**	8.34	6.52
International*	**7.72**	8.03	7.64
Total consolidated operations*	**7.73**	8.17	7.11
Equity affiliates	**7.68**	13.36	8.92
Total E&P*	**7.72**	8.33	7.19

* *Amounts in 2008 and 2007 were adjusted for certain production cost reclassifications.*

		Millions of Dollars	
Worldwide Exploration Expenses			
General and administrative; geological and geophysical; and lease rentals	$ **576**	639	544
Leasehold impairment	**247**	273	254
Dry holes	**359**	425	209
	$ **1,182**	1,337	1,007

	2009	2008	2007
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil and natural gas liquids produced			
Alaska	**252**	261	280
Lower 48	**166**	165	181
United States	**418**	426	461
Canada	**40**	44	46
Europe	**241**	233	224
Asia Pacific/Middle East	**132**	107	106
Africa	**78**	80	78
Other areas	**4**	9	10
Total consolidated operations	**913**	899	925
Equity affiliates			
Russia	**55**	24	15
Other areas	—	—	42
	968	923	982
Synthetic oil produced			
Consolidated operations—Canada	**23**	22	23
Bitumen produced			
Consolidated operations—Canada	**7**	6	—
Equity affiliates—Canada	**43**	30	27
	50	36	27
	Millions of Cubic Feet Daily		
Natural gas produced*			
Alaska	**94**	97	110
Lower 48	**1,927**	1,994	2,182
United States	**2,021**	2,091	2,292
Canada	**1,062**	1,054	1,106
Europe	**876**	954	961
Asia Pacific/Middle East	**713**	609	579
Africa	**121**	114	125
Other areas	—	14	19
Total consolidated operations	**4,793**	4,836	5,082
Equity affiliates			
Asia Pacific/Middle East	**84**	11	—
Other areas	—	—	5
	4,877	4,847	5,087

* *Represents quantities available for sale. Excludes gas equivalent of natural gas liquids included above.*

Equity affiliate statistics exclude our share of LUKOIL, which is reported in the LUKOIL Investment segment.

The E&P segment primarily explores for, produces, transports and markets crude oil, natural gas, natural gas liquids and bitumen on a worldwide basis. At December 31, 2009, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia.

2009 vs. 2008

The E&P segment had earnings of $3,604 million during 2009. In 2008, the E&P segment had a loss of $13,479 million, which included a $25,443 million before- and after-tax complete impairment of E&P segment goodwill. For additional information, see the "Goodwill Impairment" section of Note 9—Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Excluding the impact from the goodwill impairment, earnings from the E&P segment decreased 70 percent during 2009, primarily due to substantially lower crude oil, natural gas and natural gas liquids prices. Our E&P segment also recognized property impairment charges. These decreases were partially offset by lower Alaska and Lower 48 production taxes due to lower prices, as well as higher international volumes and improved operating costs. See the "Business Environment and Executive Overview" section for additional information on industry crude oil and natural gas prices.

Proved reserves at year-end 2009 were 8.36 billion barrels of oil equivalent (BOE), compared with 8.08 billion at year-end 2008. This excludes the estimated 1,967 million BOE and 1,893 million BOE included in the LUKOIL Investment segment at year-end 2009 and 2008, respectively. Also excluded for 2008 is our share of Canadian Syncrude reserves of 249 million barrels.

U.S. E&P

Earnings from our U.S. E&P operations decreased 70 percent, due to significantly lower crude oil, natural gas and natural gas liquids prices. Lower production taxes, lower property impairments in the Lower 48 and improved operating costs partially offset the decrease.

U.S. E&P production averaged 755,000 BOE per day in 2009, a decrease of 3 percent from 775,000 in 2008. Less unplanned downtime and improved well performance were more than offset by field decline.

International E&P

Earnings from our international E&P operations were $2,101 million in 2009, compared with $6,976 million in 2008. The decline was primarily a result of significantly lower crude oil, natural gas and natural gas liquids prices and higher impairments. These decreases were partially offset by higher volumes and lower operating costs.

International E&P production averaged 1,099,000 BOE per day in 2009, an increase of 8 percent from 1,014,000 in 2008. The increase was predominantly due to new production in the United Kingdom, Russia, China, Canada, Norway and Vietnam. In addition, production increased due to the impacts from the royalty framework in Alberta, Canada, as well as less unplanned downtime and the impact of lower prices on production sharing arrangements. These increases were partially offset by field decline and more planned downtime.

2008 vs. 2007

The E&P segment recorded a loss of $13,479 million during 2008. This amount included a $25,443 million before- and after-tax complete impairment of E&P segment goodwill. In 2007, the E&P segment had earnings of $4,615 million, which included the impact of a $4,588 million before-tax impairment ($4,512 million after-tax) related to the expropriation of our oil interests in Venezuela. For additional information, see the "Goodwill Impairment" section of Note 9—Goodwill and Intangibles, and the "Expropriated Assets" section of Note 10—Impairments, in the Notes to Consolidated Financial Statements, which are incorporated herein by reference.

The decrease in earnings resulted from the goodwill impairment, higher taxes other than income (mainly in Alaska), lower production volumes, higher operating and exploration costs, increased property impairments and depreciation expense, and the absence of a 2007 benefit related to release of escrowed funds associated with our Hamaca joint venture in Venezuela. The decrease was partially offset by the absence of the 2007 Venezuela impairment, as well as higher crude oil, natural gas and natural gas liquids prices. During 2008, our E&P segment recognized property impairment charges totaling $511 million after-tax, mostly due to revised capital spending plans as a result of current project economics, as well as a significantly diminished outlook for commodity prices. A large portion of these impairments relate to fields in the U.S. Lower 48 and Canada.

U.S. E&P

Earnings from our U.S. E&P operations increased 17 percent, primarily due to higher crude oil, natural gas and natural gas liquids prices. The increase was partially offset by higher production taxes (mainly in Alaska), lower volumes, an increase in impairments of properties in the Lower 48, and higher operating costs.

E&P production on a BOE basis averaged 775,000 per day in 2008, a decrease of 8 percent from 843,000 in 2007. The production decrease was primarily attributable to field decline and unplanned downtime in the Lower 48 due to hurricane disruptions.

International E&P

Earnings from our international E&P operations increased from $367 million in 2007 to $6,976 million in 2008. The increase was attributed to the impact of the Venezuelan impairment on our prior-year results and higher crude oil, natural gas and natural gas liquids prices. The increase was partially offset by higher depreciation expense due to increased rates and new assets being placed in service, increased taxes other than income, higher operating costs, and the absence of a 2007 benefit related to release of escrowed funds associated with our Hamaca joint venture in Venezuela.

International E&P production averaged 1,014,000 BOE per day in 2008, a decrease of 2 percent from 1,037,000 in 2007. Decreases in production were caused by field decline and the expropriation of our Venezuelan oil interests. These decreases were mostly offset by increased production from new developments in the United Kingdom, Indonesia, Russia, Norway and Canada.

Midstream

	2009	2008	2007
		Millions of Dollars	
Net Income Attributable to ConocoPhillips*	**$ 313**	541	453
* *Includes DCP Midstream-related earnings:*	***$ 183***	*458*	*336*

		Dollars Per Barrel	
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$ 33.63**	56.29	47.93
Equity affiliates	**29.80**	52.08	46.80

* *Based on index prices from the Mont Belvieu and Conway market hubs that are weighted by natural gas liquids component and location mix.*

		Thousands of Barrels Daily	
Operating Statistics			
Natural gas liquids extracted*	**187**	188	211
Natural gas liquids fractionated**	**166**	165	173

* *Includes our share of equity affiliates, except LUKOIL, which is included in the LUKOIL Investment segment.*

** *Excludes DCP Midstream.*

The Midstream segment purchases raw natural gas from producers and gathers natural gas through an extensive network of pipeline gathering systems. The natural gas is then processed to extract natural gas liquids from the raw gas stream. The remaining "residue" gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated—separated into individual components like ethane, butane and propane—and marketed as chemical feedstock, fuel or blendstock. The Midstream segment consists of our 50 percent equity investment in DCP Midstream, as well as our other natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, primarily in the United States and Trinidad.

2009 vs. 2008

Earnings from the Midstream segment decreased 42 percent in 2009. The decrease was primarily due to substantially lower realized natural gas liquids prices, partially offset by the recognition of an $88 million after-tax benefit in the first quarter of 2009 resulting from a DCP Midstream subsidiary converting subordinated units to common units.

2008 vs. 2007

Earnings from the Midstream segment increased 19 percent in 2008. The increase was primarily due to higher realized natural gas liquids prices, partially offset by higher operating costs and higher depreciation expense.

R&M

	2009	2008	2007
	Millions of Dollars		
Net Income (Loss) Attributable to ConocoPhillips			
United States	**$ (192)**	1,540	4,615
International	**229**	782	1,308
	$ 37	2,322	5,923

	Dollars Per Gallon		
U.S. Average Wholesale Prices*			
Gasoline	**$ 1.84**	2.65	2.27
Distillates	**1.76**	3.06	2.29

* *Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**1,986**	2,008	2,035
Crude oil processed	**1,731**	1,849	1,944
Capacity utilization (percent)	**87%**	92	96
Refinery production	**1,891**	2,035	2,146
International			
Crude oil capacity**	**671**	670	687
Crude oil processed	**495**	567	616
Capacity utilization (percent)	**74%**	85	90
Refinery production	**504**	575	633
Worldwide			
Crude oil capacity**	**2,657**	2,678	2,722
Crude oil processed	**2,226**	2,416	2,560
Capacity utilization (percent)	**84%**	90	94
Refinery production	**2,395**	2,610	2,779
Petroleum products sales volumes			
United States			
Gasoline	**1,130**	1,128	1,244
Distillates	**858**	893	872
Other products	**367**	374	432
	2,355	2,395	2,548
International	**619**	645	697
	2,974	3,040	3,245

* *Includes our share of equity affiliates, except LUKOIL, which is included in the LUKOIL Investment segment.*

** *Weighted-average crude oil capacity for the periods. Actual capacity at year-end 2007 was 2,037,000 barrels per day for our domestic refineries and 669,000 barrels per day for our international refineries.*

The R&M segment's operations encompass refining crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels); buying, selling and transporting crude oil; and buying, transporting, distributing and marketing petroleum products. R&M has operations mainly in the United States, Europe and the Asia Pacific Region.

2009 vs. 2008

R&M reported earnings of $37 million in 2009, compared with $2,322 million in 2008. The decrease was primarily a result of significantly lower U.S. and international refining margins, lower volumes, lower international marketing margins and a lower net benefit from asset rationalization efforts. These decreases were partially offset by lower operating expenses, lower property impairments and positive foreign currency exchange impacts. During 2008, our R&M segment had property impairments totaling $511 million after-tax, mostly due to a significantly diminished outlook for refining margins.

During 2009, our worldwide refining capacity utilization rate was 84 percent, compared with 90 percent in 2008.

U.S. R&M

Our U.S. R&M operations reported a loss of $192 million in 2009, compared with earnings of $1,540 million in 2008. The decrease was primarily due to significantly lower U.S. refining margins, lower U.S. refining and marketing volumes and a lower net benefit from asset sales. These decreases were partially offset by lower operating expenses and lower property impairments.

Our U.S. refining capacity utilization rate was 87 percent in 2009, compared with 92 percent in 2008. The current-year rate was mainly affected by run reductions due to market conditions and increased turnaround activity, while the prior-year rate was impacted by downtime associated with hurricanes.

International R&M

International R&M reported earnings of $229 million in 2009 and earnings of $782 million in 2008. The decrease in earnings was primarily due to significantly lower international refining and marketing margins, lower international marketing volumes and a lower net benefit from asset sales. These decreases were partially offset by positive foreign currency impacts, lower property impairments and lower operating expenses.

Our international refining capacity utilization rate was 74 percent in 2009, compared with 85 percent in 2008. The current-year rate reflects higher turnaround activity. In addition, the utilization rate for both periods reflects run reductions in response to market conditions.

2008 vs. 2007

R&M earnings decreased 61 percent in 2008. The results were lower due to decreases in U.S. refining margins and volumes, increased property impairments, higher operating costs, a reduced benefit from asset rationalization efforts, and lower international marketing and refining volumes due to asset sales. These R&M decreases were partially offset by higher international marketing margins.

During 2008, our worldwide refining capacity utilization rate was 90 percent, compared with 94 percent in 2007.

U.S. R&M

Earnings from our U.S. R&M operations decreased 67 percent in 2008. Results for 2008 also included an impairment related to one of our U.S. refineries.

Our U.S. refining capacity utilization rate was 92 percent in 2008, compared with 96 percent in 2007. The decline in the 2008 rate resulted mainly from refinery optimization and unplanned downtime, which included the impact of hurricanes on our U.S. Gulf Coast refineries.

International R&M

Earnings from our international R&M operations decreased 40 percent in 2008. Contributing to the decrease was the impairment of a refinery in Europe and the absence of a $141 million 2007 German tax legislation benefit.

Our international refining capacity utilization rate was 85 percent in 2008, compared with 90 percent during the previous year. The utilization rate was primarily impacted by reduced crude throughput at our Wilhelmshaven Refinery due to economic conditions and planned maintenance.

LUKOIL Investment

	Millions of Dollars		
	2009	2008	2007
Net Income (Loss) Attributable to ConocoPhillips	**$ 1,663**	(5,488)	1,818

Operating Statistics*			
Crude oil production (thousands of barrels daily)	**387**	386	401
Natural gas production (millions of cubic feet daily)	**280**	356	256
Refinery crude oil processed (thousands of barrels daily)	**245**	229	214

* *Represents our net share of our estimate of LUKOIL's production and processing.*

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia, which we account for under the equity method. At December 31, 2009, our ownership interest in LUKOIL was 20 percent based on authorized and issued shares. Our ownership interest based on estimated shares outstanding, used for equity method accounting, was 20.09 percent at that date.

Because LUKOIL's accounting cycle close and preparation of U.S. generally accepted accounting principles financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future-period results. In addition to our estimated equity share of LUKOIL's earnings, this segment reflects the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the book value of our investment. The segment also includes the costs associated with our employees seconded to LUKOIL.

2009 vs. 2008

The LUKOIL Investment segment had earnings of $1,663 million during 2009, compared with a loss of $5,488 million in 2008. Results for 2008 included a $7,410 million noncash, before- and after-tax impairment of our LUKOIL investment taken during the fourth quarter. For additional information, see the "LUKOIL" section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Excluding the impact of the impairment, earnings from the LUKOIL Investment segment decreased 13 percent in 2009. The decrease was primarily due to lower estimated realized refined product and crude oil prices, which was mostly offset by lower estimated extraction taxes and export tariff rates, and a benefit from basis difference amortization.

2008 vs. 2007

The LUKOIL Investment segment had a $5,488 million loss in 2008, compared with $1,818 million of earnings in 2007. Excluding the impact of the impairment, earnings from the LUKOIL Investment segment increased 6 percent in 2008. This increase was primarily due to higher estimated realized prices of both refined product and crude oil sales. Partially offsetting these positive impacts were higher estimated extraction taxes and higher estimated crude and refined product export tariff rates, as well as higher estimated operating costs and lower estimated crude volumes.

Chemicals

		Millions of Dollars	
	2009	2008	2007
Net Income Attributable to ConocoPhillips	$ **248**	110	359

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (CPChem), which we account for under the equity method. CPChem uses natural gas liquids and other feedstocks to produce petrochemicals. These products are then marketed and sold, or used as feedstocks, to produce plastics and commodity chemicals.

2009 vs. 2008

Earnings from the Chemicals segment increased $138 million in 2009 due to lower operating costs and higher margins in the specialties, aromatics and styrenics business line. These increases were partially offset by lower margins in the olefins and polyolefins business line.

2008 vs. 2007

Earnings from the Chemicals segment decreased by $249 million in 2008 due to higher utilities and other operating costs, the absence of 2007 one-time tax benefits, lower margins in the specialties, aromatics and styrenics business line, and lower volumes from the olefins and polyolefins business line. Increases in olefins and polyolefins margins somewhat offset these negative effects.

Emerging Businesses

		Millions of Dollars	
	2009	2008	2007
Net Income (Loss) Attributable to ConocoPhillips			
Power	$ **105**	106	53
Other	**(102)**	(76)	(61)
	$ **3**	30	(8)

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels, and the environment.

2009 vs. 2008

Emerging Businesses reported earnings of $3 million in 2009, compared with $30 million in 2008. The decrease was primarily due to lower international power results and higher technology development expenses, which were mostly offset by the absence of an $85 million after-tax impairment of a U.S. cogeneration power plant in 2008.

2008 vs. 2007

Emerging Businesses reported earnings of $30 million in 2008, compared with a loss of $8 million in 2007. The increase primarily reflects improved international power generation results, including the impact of higher spark spreads. These benefits were partially offset by an $85 million after-tax impairment of a U.S. cogeneration power plant, as well as by lower domestic power results.

Corporate and Other

	Millions of Dollars		
	2009	2008	2007
Net Loss Attributable to ConocoPhillips			
Net interest	**$ (851)**	(558)	(820)
Corporate general and administrative expenses	**(108)**	(202)	(176)
Acquisition/merger-related costs	**—**	—	(44)
Other	**(51)**	(274)	(229)
	$ (1,010)	(1,034)	(1,269)

2009 vs. 2008

Net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 53 percent in 2009 as a result of higher average debt levels, partially offset by lower average interest rates. Capitalized interest was also lower in 2009. Corporate general and administrative expenses decreased 47 percent due to decreased costs related to compensation plans and overhead. The category “Other” includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, and other costs not directly associated with an operating segment. Changes in the “Other” category are primarily due to higher foreign currency transaction gains.

2008 vs. 2007

Net interest decreased 32 percent in 2008, primarily due to lower average interest rates and a higher effective tax rate. Corporate general and administrative expenses increased 15 percent in 2008, mainly as a result of increased charitable contributions. Acquisition-related costs in 2007 included transition costs associated with the Burlington Resources acquisition. “Other” expenses increased in 2008 due to various tax-related adjustments, partially offset by lower foreign currency losses.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2009	2008	2007
Net cash provided by operating activities	**$ 12,479**	22,658	24,550
Short-term debt	**1,728**	370	1,398
Total debt*	**28,653**	27,455	21,687
Total equity	**63,057**	56,265	90,156
Percent of total debt to capital**	**31%**	33	19
Percent of floating-rate debt to total debt	**9**	37	25

* *Total debt includes short-term and long-term debt, as shown on our consolidated balance sheet.*

** *Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources. Cash generated from operating activities is the primary source of funding. In addition, during 2009 $1,229 million of net debt was issued, and we received $1,270 million in proceeds from asset sales. During 2009, available cash was used to support our ongoing capital expenditures and investments program, pay dividends, and meet the funding requirements to FCCL Partnership. Total dividends paid on our common stock during the year were $2,832 million. During 2009, cash and cash equivalents decreased by $213 million to $542 million.

In addition to cash flows from operating activities and proceeds from asset sales, we rely on our commercial paper and credit facility programs and our shelf registration statement to support our short- and long-term liquidity requirements. The credit markets, including the commercial paper markets in the United States, have experienced adverse conditions during 2008 and 2009. Although we have not been materially impacted by these conditions, continuing volatility in the credit markets may increase costs associated with issuing commercial paper or other debt instruments due to increased spreads over relevant interest rate benchmarks. Such volatility may also affect our ability, the ability of our joint ventures and equity affiliates, and the ability of third parties with whom we seek to do business, to access those credit markets. Notwithstanding these adverse market conditions, we believe current cash and short-term investment balances and cash generated by operations, together with access to external sources of funds as described below in the "Significant Sources of Capital" section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, dividend payments, required debt payments and the funding requirements to FCCL.

Significant Sources of Capital

Operating Activities

During 2009, cash of $12,479 million was provided by operating activities, a 45 percent decrease from cash from operations of $22,658 million in 2008. The decline was primarily due to significantly lower commodity prices in our E&P segment and lower refining margins in our R&M segment.

During 2008, cash flow from operations decreased $1,892 million, compared with 2007. Contributing to the decrease were lower U.S. refining margins and volumetric inventory builds in our R&M segment in 2008, versus reductions in 2007. These factors were partially offset by higher commodity prices in our E&P segment.

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During 2008 and 2007, we benefited from favorable crude oil and natural gas prices, although these prices deteriorated significantly in the fourth quarter of 2008. Crude oil and natural gas prices generally trended higher during 2009. Refining margins deteriorated significantly in the fourth quarter of 2008 and remained low throughout 2009. Prices and margins in our industry are typically volatile, and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of our production volumes of crude oil, natural gas and natural gas liquids also impacts our cash flows. These production levels are impacted by such factors as acquisitions and dispositions of fields, field production decline rates, new technologies, operating efficiency, weather conditions, the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although historically this variability has not been as significant as that caused by commodity prices.

Our production for 2009, including our share of production from equity affiliates, averaged 2.29 million BOE per day. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact project investment decisions; the effects of price changes on production sharing and variable-royalty contracts; timing of project startups and major turnarounds; and weather-related disruptions. Our production in 2010, including the impact of anticipated dispositions, is expected to be in the range of 2.2 million BOE per day, similar to 2008 production levels. We continue to evaluate various properties as potential candidates for our recently announced disposition program. The makeup and timing of our disposition program will also impact 2010 and future years' production levels.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our reserve replacement in 2009 was 141 percent, including 133 percent from consolidated operations. The U.S. Securities and Exchange Commission (SEC) adopted new reserves reporting rules effective in 2009, which allowed us to include Syncrude oil sands mining operations in our proved reserves. Excluding the impact of the addition of Syncrude, we replaced 112 percent of total production in 2009, reflecting progress on major projects, including the sanctioning of additional phases of in-situ oil sands projects in Canada, as well as reserve additions from our LUKOIL Investment segment. Over the five-year period ending December 31, 2009, our reserve replacement was 145 percent, including 120 percent from consolidated operations. Over this period we added reserves through acquisitions and project developments, partially offset by the impact of asset expropriations in Venezuela and Ecuador. The reserve replacement amounts above were based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. For additional information about our proved reserves, including both developed and undeveloped reserves, see the "Oil and Gas Operations" section of this report.

We are developing and pursuing projects we anticipate will allow us to add to our reserve base. However, access to additional resources has become increasingly difficult as direct investment is prohibited in some nations, while fiscal and other terms in other countries can make projects uneconomic or unattractive. In addition, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

As discussed in the "Critical Accounting Estimates" section, engineering estimates of proved reserves are imprecise, and therefore, each year reserves may be revised upward or downward due to the impact of changes in oil and gas prices or as more technical data becomes available on reservoirs. In 2009 and 2007, revisions increased reserves, while in 2008 revisions decreased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

In addition, the level and quality of output from our refineries impacts our cash flows. The output at our refineries is impacted by such factors as operating efficiency, maintenance turnarounds, market conditions, feedstock availability and weather conditions. We actively manage the operations of our refineries, and, typically, any variability in their operations has not been as significant to cash flows as that caused by refining margins.

Asset Sales

Proceeds from asset sales in 2009 were $1,270 million, compared with $1,640 million in 2008. In 2009, we closed on the sale of our ownership interest in the Keystone Pipeline and a large part of our U.S. retail marketing assets, which included seller financing in the form of a $370 million five-year note and letters of credit totaling $54 million.

We plan to raise approximately $10 billion from asset dispositions over the next two years. We will continue to identify the assets and begin marketing efforts over the near term, with disposition candidates across the company's operations being considered. Proceeds will be targeted toward debt reduction.

Commercial Paper and Credit Facilities

At December 31, 2009, we had two revolving credit facilities totaling $7.85 billion, consisting of a $7.35 billion facility expiring in September 2012 and a $500 million facility expiring in July 2012. Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, or as support for our commercial paper programs. The revolving credit facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The facility agreements contain a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or by any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreements call for commitment fees on available, but unused, amounts. The agreements also contain early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.35 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, which is used to fund commitments relating to the Qatargas 3 Project. At December 31, 2009 and 2008, we had no direct borrowings under the revolving credit facilities, but $40 million in letters of credit had been issued at both periods. In addition, under the two ConocoPhillips commercial paper programs, $1,300 million of commercial paper was outstanding at December 31, 2009, compared with $6,933 million at December 31, 2008. Since we had $1,300 million of commercial paper outstanding and had issued $40 million of letters of credit, we had access to $6.5 billion in borrowing capacity under our revolving credit facilities at December 31, 2009.

Shelf Registration

We have a universal shelf registration statement on file with the SEC under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities. Under SEC shelf registrations, in early February 2009, we issued $1.5 billion of 4.75% Notes due 2014, $2.25 billion of 5.75% Notes due 2019, and $2.25 billion of 6.50% Notes due 2039, and in May 2009, we issued $1.5 billion of 4.60% Notes due 2015, $1.0 billion of 6.00% Notes due 2020 and an additional $500 million of 6.50% Notes due 2039. The proceeds from these notes were primarily used to reduce outstanding commercial paper balances and for general corporate purposes.

Our senior long-term debt is rated "A1" by Moody's Investor Service and "A" by both Standard and Poor's Rating Service and by Fitch. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our $7.35 billion revolving credit facility and our $500 million credit facility.

Noncontrolling Interests

At December 31, 2009, and December 31, 2008, we had $590 million and $1,100 million, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. The decline from year-end 2008 was primarily due to Ashford Energy Capital S.A. redeeming for $500 million, plus accrued dividends, the investment in Ashford held by Cold Spring Finance S.a.r.l. in the third quarter of 2009. The remaining noncontrolling interests at December 31, 2009, primarily represent operating joint ventures we control. The largest of these, amounting to $565 million, was related to Darwin liquefied natural gas (LNG) operations, located in Australia's Northern Territory.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. At December 31, 2009, we were liable for certain contingent obligations under the following contractual arrangements:

- *Qatargas 3:* We own a 30 percent interest in Qatargas 3, an integrated project to produce and liquefy natural gas from Qatar's North Field. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants, based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, currently expected in 2011, all project loan facilities, including the ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2009, Qatargas 3 had approximately $3.6 billion outstanding under all the loan facilities, of which ConocoPhillips provided $1 billion, and an additional $88 million of accrued interest.
- *Rockies Express Pipeline:* In June 2006, we issued a guarantee for 24 percent of $2 billion in credit facilities issued to Rockies Express Pipeline LLC, operated by Kinder Morgan Energy Partners, L.P. Rockies Express completed construction of a natural gas pipeline across a portion of the United States in November 2009. Shortly after completion, ConocoPhillips increased its ownership from 24 to 25 percent. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $500 million, which could become payable if the credit facilities are fully utilized and Rockies Express fails to meet its obligations under the credit agreement. At December 31, 2009, Rockies Express had $1,673 million outstanding under the credit facilities, with our 25 percent guarantee equaling $418 million. The guarantee expires in April 2011. However, it is anticipated refinancing of all or a portion of the $2 billion credit facility will take place in 2010, which is expected to reduce our guarantee exposure.

For additional information about guarantees, see Note 14—Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

Our debt balance at December 31, 2009, was $28.7 billion, an increase of $1.2 billion during 2009, and our debt-to-capital ratio was 31 percent at year-end 2009, versus 33 percent at the end of 2008. The change in the debt-to-capital ratio was due to an increase in equity. Our debt-to-capital ratio target range is 20 to 25 percent.

During 2009, we used proceeds from the issuance of commercial paper to redeem $284 million of 6.375% Notes and $950 million of Floating Rate Notes upon their maturity, and prepaid $750 million of Floating Rate Five-Year Term Notes.

On January 3, 2007, we closed on a business venture with EnCana (now Cenovus). As part of this transaction, we are obligated to contribute $7.5 billion, plus accrued interest, over a 10-year period that began in 2007, to the upstream business venture, FCCL, formed as a result of the transaction. An initial contribution of $188 million was made upon closing in January. Quarterly principal and interest payments of $237 million began in the second quarter of 2007, and will continue until the balance is paid. Of the principal obligation amount, approximately $660 million was short-term and was included in the “Accounts payable—related parties” line on our December 31, 2009, consolidated balance sheet. The principal portion of these payments, which totaled $625 million in 2009, are included in the “Other” line in the financing activities section of our consolidated statement of cash flows. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as a capital contribution and is included in the “Capital expenditures and investments” line on our consolidated statement of cash flows.

We have provided loan financing to WRB Refining LLC, to assist it in meeting its operating and capital spending requirements. At December 31, 2009, $350 million of such financing was outstanding and was classified as long term.

In February 2010, we announced a quarterly dividend of 50 cents per share. The dividend is payable March 1, 2010, to stockholders of record at the close of business February 22, 2010.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2009:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Year 2-3	Year 4-5	After 5 Years
Debt obligations (a)	$ 28,622	1,719	6,311	2,806	17,786
Capital lease obligations	31	9	6	3	13
Total debt	28,653	1,728	6,317	2,809	17,799
Interest on debt and other obligations	20,680	1,678	2,866	2,363	13,773
Operating lease obligations	3,377	872	1,166	618	721
Purchase obligations (b)	112,131	45,291	13,615	9,088	44,137
Joint venture acquisition obligation (c)	5,669	660	1,427	1,586	1,996
Other long-term liabilities (d)					
Asset retirement obligations	8,295	407	519	532	6,837
Accrued environmental costs	1,017	192	222	113	490
Unrecognized tax benefits (e)	60	60	(e)	(e)	(e)
Total	$ 179,882	50,888	26,132	17,109	85,753

(a) Includes $502 million of net unamortized premiums and discounts. See Note 12—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts, including exchanges and futures, for the purchase of products such as crude oil, unfractionated natural gas liquids (NGL), natural gas and power. The products are mostly used to supply our refineries and fractionators, optimize the supply chain, and resell to customers. Product purchase commitments with third parties totaled $58,935 million. In addition, $40,739 million are product purchases from CPChem, mostly for natural gas and NGL over the remaining term of 90 years, and Excel Paralubes, for base oil over the remaining initial term of 15 years.

Purchase obligations of $8,226 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat, and store products.

The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(c) Represents the remaining amount of contributions, excluding interest, due over a seven-year period to the FCCL upstream joint venture with Cenovus.

(d) Does not include: Pensions—for the 2010 through 2014 time period, we expect to contribute an average of $540 million per year to our qualified and nonqualified pension and postretirement benefit plans in the United States and an average of $250 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. The U.S. five-year average consists of $530 million for 2010 and then approximately $540 million per year for the remaining four years. Our required minimum funding in 2010 is expected to be $130 million in the United States and $170 million outside the United States.

(e) Excludes unrecognized tax benefits of $1,148 million because the ultimate disposition and timing of any payments to be made with regard to such amount are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2010 Budget	**2009**	2008	2007
E&P				
United States—Alaska	$ 854	**810**	1,414	666
United States—Lower 48	1,621	**2,664**	3,836	3,122
International	6,470	**5,425**	11,206	6,147
	8,945	**8,899**	16,456	9,935
Midstream	14	**5**	4	5
R&M				
United States	934	**1,299**	1,643	1,146
International	385	**427**	626	240
	1,319	**1,726**	2,269	1,386
LUKOIL Investment	—	—	—	—
Chemicals	—	—	—	—
Emerging Businesses	30	**97**	156	257
Corporate and Other	157	**134**	214	208
	$ 10,465	**10,861**	19,099	11,791
United States	$ 3,590	**4,921**	7,111	5,225
International	6,875	**5,940**	11,988	6,566
	$ 10,465	**10,861**	19,099	11,791

Our capital expenditures and investments for the three-year period ending December 31, 2009, totaled $41.8 billion, with 85 percent allocated to our E&P segment.

Our capital expenditures and investments budget for 2010 is $10.5 billion. Included in this amount is approximately $500 million in capitalized interest. We plan to direct 85 percent of the capital expenditures and investments budget to E&P and 13 percent to R&M. With the addition of loans to certain affiliated companies and principal contributions related to funding our portion of the FCCL business venture, our total capital program for 2010 is approximately $11.2 billion.

E&P

Capital expenditures and investments for E&P during the three-year period ended December 31, 2009, totaled $35.3 billion. The expenditures over this period supported key exploration and development projects including:

- Oil and natural gas developments in the Lower 48, including New Mexico, Texas, Louisiana, Oklahoma, Montana, North Dakota, Colorado, Wyoming, and offshore in the Gulf of Mexico.
- The initial investment in 2008 related to the Australia Pacific LNG (APLNG) 50/50 joint venture and subsequent expenditures to advance the associated coalbed methane projects.
- Oil sands projects and ongoing natural gas projects in Canada.
- Alaska activities related to development drilling in the Greater Kuparuk Area, the Greater Prudhoe Bay Area, the Western North Slope and the Cook Inlet Area; and exploration.
- Development drilling and facilities projects in the Greater Ekofisk Area, Alvheim, Heidrun and Statfjord, located in the Norwegian sector of the North Sea.
- The Peng Lai 19-3 development in China's Bohai Bay.
- The Kashagan Field and satellite prospects in the Caspian Sea offshore Kazakhstan.
- In the U.K. sector of the North Sea, the Britannia satellite developments and various southern and central North Sea assets.
- Development of the YK Field in the northern part of Russia's Timan-Pechora province through the NMNG joint venture with LUKOIL.
- Investment in Rockies Express Pipeline LLC.
- Significant U.S. lease acquisitions in the federal waters of the Chukchi Sea offshore Alaska, as well as in the deepwater Gulf of Mexico.
- The North Belut Field, as well as other projects in offshore Block B and onshore South Sumatra in Indonesia.
- The Qatargas 3 Project, an integrated project to produce and liquefy natural gas from Qatar's North Field.
- The Gumusut-Kakap development offshore Sabah, Malaysia.

2010 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

E&P's 2010 capital expenditures and investments budget is $8.9 billion, which is essentially the same as actual expenditures in 2009. Twenty-eight percent of E&P's 2010 capital expenditures and investments budget is planned for the United States.

Capital spending for our Alaskan operations is expected to be directed toward the Prudhoe Bay and Kuparuk Fields, as well as the Alpine Field and satellites on the Western North Slope.

In the Lower 48, we expect to make capital expenditures and investments for ongoing development in the San Juan and Permian Basins and the Bakken and Lobo Trends. Also, we expect to direct capital spending towards exploration activities in the deepwater Gulf of Mexico and the Eagle Ford shale position in Texas.

E&P is directing $6.5 billion of its 2010 capital expenditures and investments budget to international projects. Funds in 2010 will be directed to developing major long-term projects including:

- Canadian oil sands projects and ongoing natural gas projects in the western Canada gas basins.
- Further development of coalbed methane projects associated with the APLNG joint venture in Australia.
- Completion of the Qatargas 3 Project in Qatar.
- Elsewhere in the Asia Pacific/Middle East Region, continued development of Bohai Bay in China, new fields offshore Malaysia, offshore Block B and onshore South Sumatra in Indonesia, and offshore Vietnam.
- In the North Sea, the Ekofisk Area, Greater Britannia Fields, various southern North Sea assets, and development of the Jasmine discovery in the J Block and the Clair Ridge Project.
- The Kashagan Field in the Caspian Sea.

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- Onshore developments in Nigeria, Algeria and Libya.
- Exploration activities in Australia's Browse Basin, Kazakhstan's Block N, offshore eastern Canada, offshore Indonesia and the North Sea, as well as a coal seam gas play in China and shale gas play in Poland.

For information on proved undeveloped reserves and the associated cost to develop these reserves, see the "Oil and Gas Operations" section.

R&M

Capital spending for R&M during the three-year period ended December 31, 2009, was primarily for clean fuels projects to meet new environmental standards, refinery upgrade projects to improve product yields and increase heavy crude oil processing capability, improving the operating integrity of key processing units, as well as for safety projects. During this three-year period, R&M capital spending was $5.4 billion, representing 13 percent of our total capital expenditures and investments.

Key projects during the three-year period included:

- Installation of a 20,000 barrel-per-day hydrocracker at the Rodeo facility of our San Francisco Refinery.
- Installation of a 25,000 barrel-per-day coker and new vacuum unit at the Borger Refinery.
- Installations, revamps and expansions of equipment at all U.S. refineries to enable production of low-sulfur and ultra-low-sulfur fuels.
- Upgrading the distillate desulfurization capability at the Humber Refinery.
- Debottlenecking of a crude and fluid catalytic cracking unit, and completion of a new sulfur plant at the Ferndale Refinery.
- Investment to obtain an equity interest in four Keystone Pipeline entities, and associated investment to construct a crude oil pipeline from Hardisty, Alberta, to delivery points in the United States. We disposed of our interest in the Keystone Pipeline in 2009.

Major construction activities in progress include:

- Installation of a 65,000 barrel-per-day coker and a major reconfiguration of the Wood River Refinery to handle advantaged crude and increase capacity, partially funded through long-term advances from ConocoPhillips.
- U.S. programs aimed at air emission reductions.

2010 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

R&M's 2010 capital budget is $1.3 billion, a 24 percent decrease from actual spending in 2009, with about $0.9 billion for its U.S. downstream businesses and $0.4 billion for international R&M. These funds will be used for projects related to sustaining and improving the existing business with a focus on safety, regulatory compliance and reliability. As previously announced, the refinery upgrade project at Wilhelmshaven has been delayed.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ended December 31, 2009, was primarily for an expansion of the Immingham combined heat and power cogeneration plant near our Humber Refinery in the United Kingdom. In addition, in October 2007, we purchased a 50 percent interest in Sweeny Cogeneration LP.

Contingencies

Legal and Tax Matters

We accrue a liability for known contingencies (other than those related to income taxes) when a loss is probable and the amounts can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. In the case of income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in the petroleum exploration and production, refining, and crude oil and refined product marketing and transportation businesses. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States.

For example, the Energy Policy Act of 2005 imposed obligations to provide increasing volumes on a percentage basis of renewable fuels in transportation motor fuels through 2012. These obligations were changed with the enactment of the Energy Independence & Security Act of 2007, which was signed in

December 2007. The 2007 law requires fuel producers and importers to provide approximately 66 percent more renewable fuels in 2008 as compared with amounts set forth in the Energy Policy Act of 2005, with further increases in amounts of renewable fuels required through 2022. We have met the increased requirements to date while establishing implementation, operating and capital strategies, along with advanced technology development, to address projected future requirements. Implementing regulations and standards for 2010 and beyond remain uncertain as the U.S. Environmental Protection Agency (EPA) has not promulgated final provisions.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Remediation obligations include cleanup responsibility arising from petroleum releases from underground storage tanks located at numerous past and present ConocoPhillips-owned and/or operated petroleum-marketing outlets throughout the United States. Federal and state laws require contamination caused by such underground storage tank releases be assessed and remediated to meet applicable standards. In addition to other cleanup standards, many states adopted cleanup criteria for methyl tertiary-butyl ether (MTBE) for both soil and groundwater.

At RCRA-permitted facilities, we are required to assess environmental conditions. If conditions warrant, we may be required to remediate contamination caused by prior operations. In contrast to CERCLA, which is often referred to as “Superfund,” the cost of corrective action activities under RCRA corrective action programs typically is borne solely by us. We anticipate increased expenditures for RCRA remediation activities may be required, but such annual expenditures for the near term are not expected to vary significantly from the range of such expenditures we have experienced over the past few years. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We, from time to time, receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2008, we reported we had been notified of potential liability under CERCLA and comparable state laws at 65 sites around the United States. At December 31, 2009, we resolved and closed two sites, re-opened one site, and received one notice of potential liability, leaving 65 unresolved sites where we have been notified of potential liability.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $1,070 million in 2009 and are expected to be about $1.1 billion per year in 2010 and 2011. Capitalized environmental costs were $891 million in 2009 and are expected to be about $830 million per year in 2010 and 2011.

We accrue for remediation activities when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. These accrued liabilities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of December 31, 2009.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2009, our balance sheet included total accrued environmental costs of $1,017 million, compared with $979 million at December 31, 2008. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

Climate Change

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol.
- California's Global Warming Solutions Act, which requires the California Air Resources Board (CARB) to develop regulations and market mechanisms that will ultimately reduce California's GHG emissions by 25 percent by 2020.
- Two regulations issued by the Alberta government in 2007 under the Climate Change and Emissions Act. These regulations require any existing facility with emissions equal to or greater than 100,000 metric tons of carbon dioxide or equivalent per year to reduce the net emissions intensity of that facility by 2 percent per year beginning July 1, 2007, with an ultimate reduction target of 12 percent of baseline emissions.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007) confirming that the EPA has the authority to regulate carbon dioxide as an "air pollutant" under the Federal Clean Air Act.
- The EPA's announcement on December 7, 2009, "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74, Fed. Reg. 66,495," finalizing its findings that GHG emissions threaten public health and the environment and that cars and light trucks cause or contribute to this threat. While these findings do not themselves impose any requirements on any industry or company at this time, these findings may lead to greater regulation of GHG emissions by the EPA, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects to determine the extent of climate change.

In the EU, we have assets that are subject to the ETS. The first phase of the EU ETS was completed at the end of 2007, with EU ETS Phase II running from 2008 through 2012. The European Commission has approved most of the Phase II national allocation plans. We are actively engaged to minimize any financial impact from the trading scheme.

In the United States, there is growing consensus that some form of regulation will be forthcoming at the federal level with respect to GHG emissions. Such regulation could take any of several forms that result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation is enacted.
- The nature of the legislation (such as a cap and trade system or a tax on emissions).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

Other

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as reductions in future taxable income.

NEW ACCOUNTING STANDARDS

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 166, “Accounting for Transfers of Financial Assets, an amendment of FASB Statement No. 140.” This Statement was codified into FASB Accounting Standards Codification (ASC) Topic 860, “Transfers and Servicing.” This Statement removes the concept of a qualifying special purpose entity (SPE) and the exception for qualifying SPEs from the consolidation guidance. Additionally, the Statement clarifies the requirements for financial asset transfers eligible for sale accounting. This Statement is effective January 1, 2010, and is not expected to have a material impact on our consolidated financial statements.

Also in June 2009, the FASB issued SFAS No. 167, “Amendments to FASB Interpretation No. 46(R),” to address the effects of the elimination of the qualifying SPE concept in SFAS No. 166, and other concerns about the application of key provisions of consolidation guidance for variable interest entities (VIEs). This Statement was codified into FASB ASC Topic 810, “Consolidation.” More specifically, SFAS No. 167 requires a qualitative rather than a quantitative approach to determine the primary beneficiary of a VIE, it amends certain guidance pertaining to the determination of the primary beneficiary when related parties are involved, and it amends certain guidance for determining whether an entity is a VIE. Additionally, this

Statement requires continuous assessments of whether an enterprise is the primary beneficiary of a VIE. This Statement is effective January 1, 2010, and is not expected to have a material impact on our consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For leasehold acquisition costs that individually are relatively small, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas that have had limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense.

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2009, the book value of the pools of property acquisition costs that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $1,466 million and the accumulated impairment reserve was $551 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 62 percent, and the weighted-average amortization period was approximately 2.5 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2010 would increase by approximately $32 million. The remaining $5,040 million of gross capitalized unproved property costs at year-end 2009 consisted of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently drilling, and suspended exploratory wells. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for project commercialization. Of this amount, approximately $2.6 billion is concentrated in 10 major development areas. One of these major assets totaling $102 million is expected to move to proved properties in 2010.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or “suspended,” on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify completion of the find as a producing well.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the mere chance that future market conditions will improve or new technologies will be found that would make the project's development economically profitable. Often, the ability to move the project into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our required return on investment.

At year-end 2009, total suspended well costs were $908 million, compared with $660 million at year-end 2008. For additional information on suspended wells, including an aging analysis, see Note 8—Suspended Wells, in the Notes to Consolidated Financial Statements.

Proved Reserves

Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's E&P operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as "proved." Our reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when a field will be permanently shut down for economic reasons is based on 12-month average prices and year-end costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes.

Our proved reserves include estimated quantities related to production sharing contracts, which are reported under the "economic interest" method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. The estimation of proved developed reserves also is important to the statement of operations because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that asset. At year-end 2009, the net book value of productive E&P properties, plants and equipment subject to a unit-of-production calculation was approximately $60 billion and the depreciation, depletion and amortization recorded on these assets in 2009 was approximately $8 billion. The estimated proved developed reserves for our consolidated operations were 5.5 billion BOE at the beginning of 2009 and were 5.6 billion BOE at the end of 2009. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pretax depreciation, depletion and amortization in 2009 would have increased by an estimated $424 million. Impairments of producing properties resulting from downward revisions of proved reserves due to reservoir performance were not material in the last three years.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually following updates to corporate planning assumptions. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets, or at an entire complex level for downstream assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs, refining margins and capital project decisions, considering all available information at the date of review. See Note 10—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value and annually following updates to corporate planning assumptions. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment's carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee's financial condition and near-term prospects, and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. When quoted market prices are not available, the fair value is usually based on the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period. For additional information, see the "LUKOIL" and "NMNG" sections of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries. The fair values of obligations for dismantling and removing these facilities are accrued at the installation of the asset based on estimated discounted costs. Estimating the future asset removal costs necessary for this accounting calculation is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

In addition, under the above or similar contracts, permits and regulations, we have certain obligations to complete environmental-related projects. These projects are primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by Canada and the state of Alaska at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties.

Business Acquisitions

Assets Acquired and Liabilities Assumed

Accounting for the acquisition of a business requires the recognition of the consideration paid, as well as the various assets and liabilities of the acquired business. For most assets and liabilities, the asset or liability is recorded at its estimated fair value. The most difficult estimates of individual fair values are those involving properties, plants and equipment and identifiable intangible assets. We use all available information to make these fair value determinations. We have, if necessary, up to one year after the acquisition closing date to finalize these fair value determinations.

Intangible Assets and Goodwill

At December 31, 2009, we had $740 million of intangible assets determined to have indefinite useful lives, thus they are not amortized. This judgmental assessment of an indefinite useful life must be continuously evaluated in the future. If, due to changes in facts and circumstances, management determines these intangible assets have definite useful lives, amortization will have to commence at that time on a prospective basis. As long as these intangible assets are judged to have indefinite lives, they will be subject to periodic lower-of-cost-or-market tests that require management's judgment of the estimated fair value of these intangible assets.

In the fourth quarter of 2008, we fully impaired the recorded goodwill associated with our Worldwide E&P reporting unit. At December 31, 2009, we had $3,638 million of goodwill remaining on our balance sheet, all of which was attributable to the Worldwide R&M reporting unit. See Note 9—Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information on intangibles and goodwill, including a detailed discussion of the facts and circumstances leading to the goodwill impairment, as well as the judgments required by management in the analysis leading to the impairment determination.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the statement of operations. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plan. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $140 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $60 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words "anticipate," "estimate," "believe," "continue," "could," "intend," "may," "plan," "potential," "predict," "should," "will," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

- Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Failure of new products and services to achieve market acceptance.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production, manufacturing, refining or transportation projects.
- Unexpected technological or commercial difficulties in manufacturing, refining or transporting our products, including synthetic crude oil and chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, LNG and refined products.
- Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, or refinery projects; comply with government regulations; or make capital expenditures required to maintain compliance.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future exploration and production, LNG, refinery and transportation projects.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism.
- International monetary conditions and exchange controls.
- Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing, regulation or taxation; other political, economic or diplomatic developments; and international monetary fluctuations.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.

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- Limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Delays in, or our inability to implement, our recently announced asset disposition plan.
- Inability to obtain economical financing for projects, construction or modification of facilities and general corporate purposes.
- The operation and financing of our midstream and chemicals joint ventures.
- The factors generally described in Item 1A—Risk Factors in this report.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of electric power, natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an "Authority Limitations" document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates and reports to the Chief Executive Officer. The Senior Vice President of Commercial monitors commodity price risk and reports to the Chief Operating Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors related risks of our upstream and downstream businesses.

Commodity Price Risk

We operate in the worldwide crude oil, refined products, natural gas, natural gas liquids, and electric power markets and are exposed to fluctuations in the prices for these commodities. These fluctuations can affect our revenues, as well as the cost of operating, investing and financing activities. Generally, our policy is to remain exposed to the market prices of commodities.

Our Commercial organization uses futures, forwards, swaps and options in various markets to optimize the value of our supply chain, which may move our risk profile away from market average prices to accomplish the following objectives:

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange-traded futures contracts also may be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand.
- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price.
- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions.
- Enable us to use the market knowledge gained from these activities to do a limited amount of commodity trading around our asset base.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments held or issued, including commodity purchase and sales contracts recorded on the balance sheet at December 31, 2009, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes at December 31, 2009 and 2008, was immaterial to our cash flows and net income attributable to ConocoPhillips.

The VaR for instruments held for purposes other than trading at December 31, 2009 and 2008, was also immaterial to our cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk

The following table provides information about our financial instruments that are sensitive to changes in short-term U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on implied forward rates in the yield curve at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices. The joint venture acquisition obligation portion of the table presents principal cash flows of the fixed-rate 5.3 percent joint venture acquisition obligation owed to FCCL Partnership. The fair value of the obligation is estimated based on the net present value of the future cash flows, discounted at a year-end 2009 and 2008 effective yield rate of 2.63 percent and 5.4 percent, respectively, based on yields of U.S. Treasury securities of a similar average duration adjusted for ConocoPhillips' average credit risk spread and the amortizing nature of the obligation principal.

	Millions of Dollars Except as Indicated					
	Debt				Joint Venture Acquisition Obligation	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate	Fixed Rate Maturity	Average Interest Rate
Year-End 2009						
2010	**$ 1,439**	**8.82%**	**$ —**	**—%**	**$ 660**	**5.30%**
2011	**3,183**	**6.72**	**750**	**0.45**	**695**	**5.30**
2012	**1,264**	**4.94**	**1,303**	**0.25**	**732**	**5.30**
2013	**1,262**	**5.33**	**—**	**—**	**772**	**5.30**
2014	**1,513**	**4.77**	**3**	**2.01**	**814**	**5.30**
Remaining years	**16,805**	**6.28**	**598**	**0.61**	**1,996**	**5.30**
Total	**$ 25,466**		**$ 2,654**		**$ 5,669**	
Fair value	**$ 27,911**		**$ 2,654**		**$ 6,276**	
Year-End 2008						
2009	$ 303	6.43%	$ 950	4.42%	625	5.30%
2010	1,441	8.83	—	—	659	5.30
2011	3,174	6.74	1,500	1.64	695	5.30
2012	1,266	4.94	6,936	1.23	733	5.30
2013	1,262	5.33	10	2.46	772	5.30
Remaining years	9,318	6.64	628	2.58	2,810	5.30
Total	$ 16,764		$ 10,024		$ 6,294	
Fair value	$ 16,882		$ 10,024		$ 6,294	

Foreign Currency Risk

We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2009 and 2008, we held foreign currency swaps hedging short-term intercompany loans between European subsidiaries and a U.S. subsidiary. Although these swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting as allowed by FASB ASC Topic 815. As a result, the change in the fair value of these foreign currency swaps is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the intercompany loans into the functional currency of the lender or borrower, there would be no material impact to income from an adverse hypothetical 10 percent change in the December 31, 2009 or 2008, exchange rates. The notional and fair market values of these positions at December 31, 2009 and 2008, were as follows:

		In Millions			
		Notional*		Fair Market Value**	
Foreign Currency Swaps		**2009**	2008	**2009**	2008
Sell U.S. dollar, buy euro	USD	**246**	526	**$ (2)**	53
Sell U.S. dollar, buy British pound	USD	**1,664**	1,657	**(16)**	(46)
Sell U.S. dollar, buy Canadian dollar	USD	**554**	1,474	**34**	13
Sell U.S. dollar, buy Czech koruna	USD	**—**	40	**—**	(2)
Sell U.S. dollar, buy Danish krone	USD	**—**	5	**—**	—
Sell U.S. dollar, buy Norwegian kroner	USD	**744**	1,103	**(4)**	(10)
Sell U.S. dollar, buy Swedish krona	USD	**—**	51	**—**	1
Sell U.S. dollar, buy Australian dollar	USD	**3**	246	**—**	3
Sell euro, buy Canadian dollar	EUR	**—**	102	**—**	—
Sell euro, buy British pound	EUR	**267**	—	**(14)**	—
Buy euro, sell British pound	EUR	**—**	147	**—**	(8)

* *Denominated in U.S. dollars (USD) and euro (EUR).*

** *Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 16—Financial Instruments and Derivative Contracts, in the Notes to Consolidated Financial Statements.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2009. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. Based on our assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2009.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2009, and their report is included herein.

/s/ James J. Mulva	/s/ Sigmund L. Cornelius
James J. Mulva Chairman and Chief Executive Officer	**Sigmund L. Cornelius** Senior Vice President, Finance, and Chief Financial Officer

February 25, 2010

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the related condensed consolidating financial information listed in the Index at Item 8 and financial statement schedule listed in Item 15(a). These financial statements, condensed consolidating financial information, and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information, and schedule based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in 2009 ConocoPhillips has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), ConocoPhillips' 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 and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2010

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders
ConocoPhillips

We have audited ConocoPhillips' 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 (the COSO criteria). ConocoPhillips' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Report of Management." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2009 consolidated financial statements of ConocoPhillips and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2010

Consolidated Statement of Operations **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2009	2008	2007
Revenues and Other Income			
Sales and other operating revenues*	$ **149,341**	240,842	187,437
Equity in earnings of affiliates	**2,981**	4,250	5,087
Other income	**518**	1,090	1,971
Total Revenues and Other Income	**152,840**	246,182	194,495
Costs and Expenses			
Purchased crude oil, natural gas and products	**102,433**	168,663	123,429
Production and operating expenses	**10,339**	11,818	10,683
Selling, general and administrative expenses	**1,830**	2,229	2,306
Exploration expenses	**1,182**	1,337	1,007
Depreciation, depletion and amortization	**9,295**	9,012	8,298
Impairments			
Goodwill	**—**	25,443	—
LUKOIL investment	**—**	7,410	—
Expropriated assets**	**51**	—	4,588
Other	**484**	1,686	442
Taxes other than income taxes*	**15,529**	20,637	18,990
Accretion on discounted liabilities	**422**	418	341
Interest and debt expense	**1,289**	935	1,253
Foreign currency transaction (gains) losses	**(46)**	117	(201)
Total Costs and Expenses	**142,808**	249,705	171,136
Income (loss) before income taxes	**10,032**	(3,523)	23,359
Provision for income taxes	**5,096**	13,405	11,381
Net income (loss)	**4,936**	(16,928)	11,978
Less: net income attributable to noncontrolling interests	**(78)**	(70)	(87)
Net Income (Loss) Attributable to ConocoPhillips	$ **4,858**	(16,998)	11,891
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)****			
Basic	$ **3.26**	(11.16)	7.32
Diluted	**3.24**	(11.16)	7.22
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,487,650**	1,523,432	1,623,994
Diluted	**1,497,608**	1,523,432	1,645,919
* *Includes excise taxes on petroleum products sales:*	*$* ***13,325***	*15,418*	*15,937*

** *Includes allocated goodwill.*

*** *For the purpose of the earnings per share calculation only, 2009 net income attributable to ConocoPhillips has been reduced by $12 million for the excess of the amount paid for the redemption of a noncontrolling interest over its carrying value, which was charged directly to retained earnings.*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31	Millions of Dollars 2009	2008
Assets		
Cash and cash equivalents	**$ 542**	755
Accounts and notes receivable (net of allowance of $76 million in 2009 and $61 million in 2008)	**11,861**	10,892
Accounts and notes receivable—related parties	**1,354**	1,103
Inventories	**4,940**	5,095
Prepaid expenses and other current assets	**2,470**	2,998
Total Current Assets	**21,167**	20,843
Investments and long-term receivables	**36,192**	30,926
Loans and advances—related parties	**2,352**	1,973
Net properties, plants and equipment	**87,708**	83,947
Goodwill	**3,638**	3,778
Intangibles	**823**	846
Other assets	**708**	552
Total Assets	**$ 152,588**	142,865
Liabilities		
Accounts payable	**$ 14,168**	12,852
Accounts payable—related parties	**1,317**	1,138
Short-term debt	**1,728**	370
Accrued income and other taxes	**3,402**	4,273
Employee benefit obligations	**846**	939
Other accruals	**2,234**	2,208
Total Current Liabilities	**23,695**	21,780
Long-term debt	**26,925**	27,085
Asset retirement obligations and accrued environmental costs	**8,713**	7,163
Joint venture acquisition obligation—related party	**5,009**	5,669
Deferred income taxes	**17,962**	18,167
Employee benefit obligations	**4,130**	4,127
Other liabilities and deferred credits	**3,097**	2,609
Total Liabilities	**89,531**	86,600
Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2009—1,733,345,558 shares; 2008—1,729,264,859 shares)		
Par value	**17**	17
Capital in excess of par	**43,681**	43,396
Grantor trusts (at cost: 2009—38,742,261 shares; 2008—40,739,129 shares)	**(667)**	(702)
Treasury stock (at cost: 2009 and 2008—208,346,815 shares)	**(16,211)**	(16,211)
Accumulated other comprehensive income (loss)	**3,065**	(1,875)
Unearned employee compensation	**(76)**	(102)
Retained earnings	**32,658**	30,642
Total Common Stockholders' Equity	**62,467**	55,165
Noncontrolling interests	**590**	1,100
Total Equity	**63,057**	56,265
Total Liabilities and Equity	**$ 152,588**	142,865

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars		
Years Ended December 31	**2009**	2008	2007
Cash Flows From Operating Activities			
Net income (loss)	**$ 4,936**	(16,928)	11,978
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**9,295**	9,012	8,298
Impairments	**535**	34,539	5,030
Dry hole costs and leasehold impairments	**606**	698	463
Accretion on discounted liabilities	**422**	418	341
Deferred taxes	**(1,109)**	(428)	(33)
Undistributed equity earnings	**(1,704)**	(1,609)	(1,823)
Gain on asset dispositions	**(160)**	(891)	(1,348)
Other	**196**	(1,134)	89
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**(1,106)**	4,225	(2,492)
Decrease (increase) in inventories	**320**	(1,321)	767
Decrease (increase) in prepaid expenses and other current assets	**282**	(724)	487
Increase (decrease) in accounts payable	**1,612**	(3,874)	2,772
Increase (decrease) in taxes and other accruals	**(1,646)**	675	21
Net Cash Provided by Operating Activities	**12,479**	22,658	24,550
Cash Flows From Investing Activities			
Capital expenditures and investments	**(10,861)**	(19,099)	(11,791)
Proceeds from asset dispositions	**1,270**	1,640	3,572
Long-term advances/loans—related parties	**(525)**	(163)	(682)
Collection of advances/loans—related parties	**93**	34	89
Other	**88**	(28)	250
Net Cash Used in Investing Activities	**(9,935)**	(17,616)	(8,562)
Cash Flows From Financing Activities			
Issuance of debt	**9,087**	7,657	935
Repayment of debt	**(7,858)**	(1,897)	(6,454)
Issuance of company common stock	**13**	198	285
Repurchase of company common stock	**—**	(8,249)	(7,001)
Dividends paid on company common stock	**(2,832)**	(2,854)	(2,661)
Other	**(1,265)**	(619)	(444)
Net Cash Used in Financing Activities	**(2,855)**	(5,764)	(15,340)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**98**	21	(9)
Net Change in Cash and Cash Equivalents	**(213)**	(701)	639
Cash and cash equivalents at beginning of year	**755**	1,456	817
Cash and Cash Equivalents at End of Year	**$ 542**	755	1,456

See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Equity **ConocoPhillips**

	Millions of Dollars									
	Attributable to ConocoPhillips									
	Common Stock									
	Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Accum. Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
December 31, 2006	$ 17	41,926	(964)	(766)	1,289	(148)	41,292		1,202	83,848
Net income							11,891	11,891	87	11,978
Other comprehensive income (loss)										
Defined benefit pension plans										
Net prior service cost					63			63		63
Net actuarial gain					213			213		213
Nonsponsored plans					(2)			(2)		(2)
Foreign currency translation adjustments					3,075			3,075		3,075
Hedging activities					(4)			(4)		(4)
Comprehensive income								15,236	87	15,323
Initial application of SFAS No. 158—equity affiliate					(74)					(74)
Cash dividends paid on company common stock							(2,661)			(2,661)
Repurchase of company common stock			(7,005)	11						(6,994)
Distributions to noncontrolling interests and other									(116)	(116)
Distributed under benefit plans		798		31						829
Recognition of unearned compensation						20				20
Other				(7)			(12)			(19)
December 31, 2007	17	42,724	(7,969)	(731)	4,560	(128)	50,510		1,173	90,156
Net income (loss)							(16,998)	(16,998)	70	(16,928)
Other comprehensive income (loss)										
Defined benefit pension plans										
Net prior service cost					22			22		22
Net actuarial loss					(950)			(950)		(950)
Nonsponsored plans					(41)			(41)		(41)
Foreign currency translation adjustments					(5,464)			(5,464)		(5,464)
Hedging activities					(2)			(2)		(2)
Comprehensive income (loss)								(23,433)	70	(23,363)
Cash dividends paid on company common stock							(2,854)			(2,854)
Repurchase of company common stock			(8,242)	1						(8,241)
Distributions to noncontrolling interests and other									(143)	(143)
Distributed under benefit plans		672		28						700
Recognition of unearned compensation						26				26
Other							(16)			(16)
December 31, 2008	17	43,396	(16,211)	(702)	(1,875)	(102)	30,642		1,100	56,265
Net income							**4,858**	**4,858**	**78**	**4,936**
Other comprehensive										

income (loss)										
Defined benefit pension plans										
Net prior service cost					**7**			**7**		**7**
Net actuarial loss					**(99)**			**(99)**		**(99)**
Nonsponsored plans					**22**			**22**		**22**
Foreign currency translation adjustments					**5,007**			**5,007**		**5,007**
Hedging activities					**3**			**3**		**3**
Comprehensive income								**9,798**	**78**	**9,876**
Cash dividends paid on company common stock							**(2,832)**			**(2,832)**
Distributions to noncontrolling interests and other									**(588)**	**(588)**
Distributed under benefit plans		**285**		**35**						**320**
Recognition of unearned compensation						**26**				**26**
Other							**(10)**			**(10)**
December 31, 2009	**$ 17**	**43,681**	**(16,211)**	**(667)**	**3,065**	**(76)**	**32,658**		**590**	**63,057**

See Notes to Consolidated Financial Statements.

Note 1—Accounting Policies

- **Consolidation Principles and Investments—**Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. The cost method is used when we do not have the ability to exert significant influence. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments, excluding marketable securities, are generally carried at cost.

- **Foreign Currency Translation—**Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income (loss) in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Most of our foreign operations use their local currency as the functional currency.

- **Use of Estimates—**The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

- **Revenue Recognition—**Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

  Revenues associated with properties producing natural gas and crude oil, in which we have an interest with other producers, are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

  Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same income statement line).

- **Shipping and Handling Costs—**Our Exploration and Production (E&P) segment includes shipping and handling costs in production and operating expenses for production activities. Transportation costs related to E&P marketing activities are recorded in purchased crude oil, natural gas and products. The Refining and Marketing (R&M) segment records shipping and handling costs in purchased crude oil, natural gas and products. Freight costs billed to customers are recorded as a component of revenue.

- **Cash Equivalents—**Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of three months or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Inventories—**We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Crude oil and petroleum products inventories are valued at the lower of cost or market in the aggregate, primarily on the last-in, first-out (LIFO) basis. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues and to meet tax-conformity requirements. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued under various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with industry practice.

- **Fair Value Measurements—**We categorize assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

- **Derivative Instruments—**All derivative instruments are recorded on the balance sheet at fair value in either prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge or hedge of a net investment in a foreign entity will be recorded on the balance sheet in accumulated other comprehensive income (loss) until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

  In the consolidated statement of operations, gains and losses from derivatives that are held for trading and not directly related to our physical business are recorded in other income. Gains and losses from derivatives used for other purposes are recorded in sales and other operating revenues; other income; purchased crude oil, natural gas and products; interest and debt expense; or foreign currency transaction (gains) losses, depending on the purpose for issuing or holding the derivatives.

- **Oil and Gas Exploration and Development—**Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  Property Acquisition Costs—Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

  Exploratory Costs—Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 8—Suspended Wells for additional information on suspended wells.

Development Costs—Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depletion and Amortization—Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Capitalized Interest—**Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Intangible Assets Other Than Goodwill—**Intangible assets that have finite useful lives are amortized by the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized but are tested at least annually for impairment. Each reporting period, we evaluate the remaining useful lives of intangible assets not being amortized to determine whether events and circumstances continue to support indefinite useful lives. These indefinite lived intangibles are considered impaired if the fair value of the intangible asset is lower than net book value. The fair value of intangible assets is determined based on quoted market prices in active markets, if available. If quoted market prices are not available, fair value of intangible assets is determined based upon the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or upon estimated replacement cost, if expected future cash flows from the intangible asset are not determinable.

- **Goodwill—**Goodwill resulting from a business combination is not amortized but is tested at least annually for impairment. If the fair value of a reporting unit is less than the recorded book value of the reporting unit's assets (including goodwill), less liabilities, then a hypothetical purchase price allocation is performed on the reporting unit's assets and liabilities using the fair value of the reporting unit as the purchase price in the calculation. If the amount of goodwill resulting from this hypothetical purchase price allocation is less than the recorded amount of goodwill, the recorded goodwill is written down to the new amount. For purposes of goodwill impairment calculations, two reporting units have been determined: Worldwide Exploration and Production and Worldwide Refining and Marketing.

- **Depreciation and Amortization—**Depreciation and amortization of properties, plants and equipment on producing hydrocarbon properties and certain pipeline assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other properties, plants and equipment are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment—**Properties, plants and equipment used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually following updates to corporate planning assumptions. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for exploration and production assets, or at an entire complex level for refining assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. If the future production price risk has been hedged, the hedged price is used in the calculations for the period and quantities hedged. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

n **Impairment of Investments in Nonconsolidated Entities—**Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

n **Maintenance and Repairs—**Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

n **Advertising Costs—**Production costs of media advertising are deferred until the first public showing of the advertisement. Advances to secure advertising slots at specific sporting or other events are deferred until the event occurs. All other advertising costs are expensed as incurred, unless the cost has benefits that clearly extend beyond the interim period in which the expenditure is made, in which case the advertising cost is deferred and amortized ratably over the interim periods that clearly benefit from the expenditure.

n **Property Dispositions—**When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in other income. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

n **Asset Retirement Obligations and Environmental Costs—**Fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset. See Note 11—Asset Retirement Obligations and Accrued Environmental Costs, for additional information.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have a future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable and estimable.

- **Guarantees—**Fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information that the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related statement of operations line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Stock-Based Compensation—**We recognize stock-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **Income Taxes—**Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest expense, and penalties in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities—**Excise taxes are reported gross within sales and other operating revenues and taxes other than income taxes, while other sales and value-added taxes are recorded net in taxes other than income taxes.

- **Net Income (Loss) Per Share of Common Stock—**Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including unallocated shares held by the stock savings feature of the ConocoPhillips Savings Plan. Also, this calculation includes fully vested stock and unit awards that have not been issued. Diluted net income per share of common stock includes the above, plus unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share. Diluted net loss per share in 2008 is calculated the same as basic net loss per share —that is, it does not assume conversion or exercise of securities, totaling 17,354,959 shares in 2008 that would have an anti-dilutive effect. Treasury stock and shares held by the grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations.

Note 2—Changes in Accounting Principles

Reserve Estimation and Disclosures

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-03, "Oil and Gas Reserve Estimation and Disclosures." This ASU amends the FASB's Accounting Standards Codification (ASC) Topic 932, "Extractive Activities—Oil and Gas" to align the accounting requirements of Topic 932 with the Securities and Exchange Commission's final rule, "Modernization of the Oil and Gas Reporting Requirements" issued on December 31, 2008. In summary, the revisions in ASU 2010-3 modernize the disclosure rules to better align with current industry practices and expand the disclosure requirements for equity method investments so that more useful information is provided. More specifically, the main provisions include the following:

- An expanded definition of oil and gas producing activities to include nontraditional resources such as bitumen extracted from oil sands.
- The use of an average of the first-day-of-the-month price for the 12-month period, rather than a year-end price for determining whether reserves can be produced economically.
- Amended definitions of key terms such as "reliable technology" and "reasonable certainty" which are used in estimating proved oil and gas reserve quantities.
- A requirement for disclosing separate information about reserve quantities and financial statement amounts for geographical areas representing 15 percent or more of proved reserves.
- Clarification that an entity's equity investments must be considered in determining whether it has significant oil and gas activities and a requirement to disclose equity method investments in the same level of detail as is required for consolidated investments.

This ASU is effective for annual reporting periods ended on or after December 31, 2009, and it requires (1) the effect of the adoption to be included within each of the dollar amounts and quantities disclosed, (2) qualitative and quantitative disclosure of the estimated effect of adoption on each of the dollar amounts and quantities disclosed, if significant and practical to estimate and (3) the effect of adoption on the financial statements, if significant and practical to estimate. Adoption of these requirements did not significantly impact our reported reserves or our consolidated financial statements.

Codification

The FASB issued ASU No. 2009-01 in June 2009. This Update, also issued as FASB Statement of Financial Accounting Standards (SFAS) No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles," is effective for financial statements issued after September 15, 2009. Update 2009-01 requires that the FASB's ASC become the sole source of authoritative U.S. generally accepted accounting principles recognized by the FASB for nongovernmental entities. We adopted this Update effective July 1, 2009.

Subsequent Events

Effective April 1, 2009, we adopted FASB SFAS No. 165, "Subsequent Events." This Statement was codified into FASB ASC Topic 855, "Subsequent Events." Topic 855 establishes the accounting for, and disclosure of, material events that occur after the balance sheet date, but before the financial statements are issued. In general, these events will be recognized if the condition existed at the date of the balance sheet, and will not be recognized if the condition did not exist at the balance sheet date. Disclosure is required for nonrecognized events if required to keep the financial statements from being misleading. The guidance in this Topic is very similar to previous guidance provided in auditing literature and, therefore, did not result in significant changes in practice.

Business Combinations

In December 2007, the FASB issued SFAS No. 141 (Revised), "Business Combinations" (SFAS No. 141(R)), which was subsequently amended by FASB Staff Position (FSP) FAS 141(R)-1 in April 2009. This Statement was codified into FASB ASC Topic 805, "Business Combinations." Topic 805 applies prospectively to all transactions in which an entity obtains control of one or more other businesses on or after January 1, 2009. In general, Topic 805 requires the acquiring entity in a business combination to recognize the fair value of all assets acquired and liabilities assumed in the transaction; establishes the acquisition date as the fair value measurement point; and modifies disclosure requirements. It also modifies the accounting treatment for transaction costs, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of a business combination, and changes in income tax uncertainties after the acquisition date. Additionally, effective January 1, 2009, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations impact tax expense instead of goodwill.

Noncontrolling Interests

Effective January 1, 2009, we implemented SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51." This Statement was codified into FASB ASC Topic 810, "Consolidation." Topic 810 requires noncontrolling interests, previously called minority interests, to be presented as a separate item in the equity section of the consolidated balance sheet. It also requires the amount of consolidated net income attributable to noncontrolling interests to be clearly presented on the face of the consolidated income statement. Additionally, Topic 810 clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions, and that deconsolidation of a subsidiary requires gain or loss recognition in net income based on the fair value on the deconsolidation date. Topic 810 was applied prospectively with the exception of presentation and disclosure requirements, which were applied retrospectively for all periods presented, and did not significantly change the presentation of our consolidated financial statements. FASB ASU No. 2010-02, "Accounting and Reporting for Decreases in Ownership of a Subsidiary—a Scope Clarification," clarified the decrease in ownership provision of Topic 810 applies to a group of assets or a subsidiary that is a business, but was not applicable to sales of in-substance real estate, or conveyances of oil and gas mineral rights.

Derivatives

Effective January 1, 2009, we implemented SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB No. 133." This Statement was codified into FASB ASC Topic 815, "Derivatives and Hedging." The amendments to Topic 815 expanded disclosure requirements to provide greater transparency for derivative instruments. In addition, we now must include an indication of the volume of derivative activity by category (e.g., interest rate, commodity and foreign currency); derivative gains and losses, by category, for the periods presented in the financial statements; and expanded disclosures about credit-risk-related contingent features. See Note 16—Financial Instruments and Derivative Contracts, for additional information.

Fair Value Measurement

Effective January 1, 2008, we implemented SFAS No. 157, "Fair Value Measurements." This Statement was codified primarily into FASB ASC Topic 820, "Fair Value Measurements and Disclosures." This Topic defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We elected to implement this guidance with the one-year deferral permitted for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis (at least annually). Following the allowed one-year deferral, effective January 1, 2009, we implemented Topic 820 for nonfinancial assets and nonfinancial liabilities measured at fair value on a nonrecurring basis. The implementation covers assets and liabilities measured at fair value in a business combination; impaired properties, plants and equipment, intangible assets and goodwill; initial recognition of asset retirement obligations; and restructuring costs for which we use fair value. There was no impact to our consolidated financial statements from the implementation of this Topic for nonfinancial assets and liabilities, other than additional disclosures.

Financial Instruments

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115." This Statement was codified into FASB ASC Topic 825, "Financial Instruments." Topic 825 permits the election to carry financial instruments and certain other items similar to financial instruments at fair value on the balance sheet, with all changes in fair value reported in earnings. By electing the fair value option in conjunction with a derivative, an entity can achieve an accounting result similar to a fair value hedge without having to comply with complex hedge accounting rules. We adopted this Statement effective January 1, 2008, but did not make a fair value election at that time or during the remaining period of 2008 through the year 2009 for any financial instruments not already carried at fair value in accordance with other accounting standards. Accordingly, the adoption of SFAS No. 159 did not impact our consolidated financial statements.

Compensation—Retirement Benefits

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)." This Statement was codified into FASB ASC Topic 715, "Compensation—Retirement Benefits." Topic 715 requires an employer that sponsors one or more single-employer defined benefit plans to:

- Recognize the funded status of the benefit in its statement of financial position.
- Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost.
- Measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position.
- Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and the transition asset or obligation.

We adopted the provisions of this Statement effective December 31, 2006, except for the requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year end, which we adopted effective December 31, 2008. For information on the impact of the adoption of this Statement, see Note 19—Employee Benefit Plans.

Equity Method Accounting

In November 2008, the FASB reached a consensus on Emerging Issues Task Force (EITF) Issue No. 08-6, "Equity Method Investment Accounting Considerations" (EITF 08-6). EITF 08-6 was codified into FASB ASC Topic 323, "Investments—Equity Method and Joint Ventures." EITF 08-6 was issued to clarify how the application of equity method accounting is affected by SFAS No. 141(R) and SFAS No. 160. Topic 323 clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of contingent consideration and the use of the impairment model under Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This Topic was effective January 1, 2009, and applies prospectively. The adoption did not impact our consolidated financial statements.

Financial Assets and Variable Interest Entities

In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, "Disclosures about Transfers of Financial Assets and Interest in Variable Interest Entities." This FSP was codified into FASB ASC Topic 810, "Consolidation." Topic 810 requires additional disclosures about an entity's involvement with a variable interest entity (VIE) and certain transfers of financial assets to special-purpose entities and VIEs. This FSP was effective December 31, 2008, and the additional disclosures related to VIEs have been incorporated into Note 3—Variable Interest Entities (VIEs), including the methodology for determining whether we are the primary beneficiary of a VIE, whether we have provided financial or other support we were not contractually required to provide, and other qualitative and quantitative information. We did not have any transfers of financial assets within the scope of Topic 810.

Postretirement Benefit Plan Assets

In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets," to improve the transparency associated with disclosures about the plan assets of a defined benefit pension or other postretirement plan. This Statement was codified into FASB ASC Topic 715, "Compensation—Retirement Benefits." Topic 715 requires the disclosure of each major asset class at fair value using the fair value hierarchy in SFAS No. 157, "Fair Value Measurements." This Topic is effective for annual financial statements beginning with the 2009 fiscal year, but did not impact our consolidated financial statements, other than requiring additional disclosures. For more information on this disclosure, see Note 19—Employee Benefit Plans.

Note 3—Variable Interest Entities (VIEs)

We hold significant variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on these VIEs follows. See Note 26—New Accounting Standards, for information affecting the accounting for VIEs effective January 1, 2010.

We have a 30 percent ownership interest with a 50 percent governance interest in the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the Timan-Pechora province of Russia. The NMNG joint venture is a VIE because we and a related party, OAO LUKOIL, have disproportionate interests. When related parties are involved in a VIE, reasonable judgment should take into account the relevant facts and circumstances for the determination of the primary beneficiary. The activities of NMNG are more closely aligned with LUKOIL because they share Russia as a home country, and LUKOIL conducts extensive exploration activities in the same province. Additionally, there are no financial guarantees given by LUKOIL or us, and LUKOIL owns 70 percent, versus our 30 percent direct interest. As a result, we have determined we are not the primary beneficiary of NMNG, and we use the equity method of accounting for this investment. The funding of NMNG has been provided with equity contributions, primarily for the development of the Yuzhno Khylchuyu (YK) Field. Initial production from YK was achieved in June 2008. At December 31, 2009, the book value of our investment in the venture was $1,647 million.

Production from the NMNG joint venture fields is transported via pipeline to LUKOIL's terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL completed an expansion of the terminal's gross oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day, and we participated in the design and financing of the expansion. The terminal entity, Varandey Terminal Company, is a VIE because we and LUKOIL have disproportionate interests. We had an obligation to fund, through loans, 30 percent of the terminal's expansion costs, but have no governance or direct ownership interest in the terminal. Similar to NMNG, we determined we are not the primary beneficiary for Varandey because of LUKOIL's ownership, the activities are in LUKOIL's home country, and LUKOIL is the operator of Varandey. We account for our loan to Varandey as a financial asset. Terminal expansion was completed in June 2008. Principal repayments began in April 2009. The loan balance outstanding as of December 31, 2009, at current exchange rates, was $278 million.

We have an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in a liquefied natural gas (LNG) receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we own a 50 percent interest in Freeport LNG GP, Inc. (Freeport GP), which serves as the general partner managing the venture. We entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity. The terminal became operational in June 2008, and we began making payments under the terminal use agreement. Freeport LNG began making loan repayments in September 2008, and the loan balance outstanding as of December 31, 2009, was $707 million. Freeport LNG is a VIE because Freeport GP holds no equity in Freeport LNG, and the limited partners of Freeport LNG do not have any substantive decision making ability. We performed an analysis of the expected losses and determined we are not the primary beneficiary. This expected loss analysis took into account that the credit support arrangement requires Freeport LNG to maintain sufficient commercial insurance to mitigate any loan losses. The loan to Freeport LNG is accounted for as a financial asset, and our investment in Freeport GP is accounted for as an equity investment.

In the third quarter of 2009, Ashford Energy Capital S.A. redeemed for $500 million, plus accrued dividends, the investment in Ashford held by Cold Spring Finance S.a.r.l. Accordingly, we wholly own Ashford, and it is no longer a VIE.

Our ownership in Rockies Express Pipeline LLC, was previously reported as a VIE because a third party with no ownership interest had a 49 percent voting interest through the end of the construction phase of the pipeline. With completion of construction in November 2009, our ownership increased from 24 to 25 percent and is now aligned with our voting interest. Rockies Express Pipeline is no longer considered a VIE.

Note 4—Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2009	2008
Crude oil and petroleum products	**$ 3,955**	4,232
Materials, supplies and other	**985**	863
	$ 4,940	5,095

Inventories valued on the LIFO basis totaled $3,747 million and $3,939 million at December 31, 2009 and 2008, respectively. The excess of current replacement cost over LIFO cost of inventories amounted to $5,627 million and $1,959 million at December 31, 2009 and 2008, respectively. In 2007, a liquidation of LIFO inventory values increased net income attributable to ConocoPhillips $280 million, of which $260 million was attributable to our R&M segment.

Note 5—Assets Held for Sale

At December 31, 2008, we classified $594 million of noncurrent assets, primarily properties, plants and equipment, and $92 million of noncurrent liabilities, primarily deferred taxes, as held for sale on the consolidated balance sheet. During 2009, we closed on the sale of a large part of our U.S. retail marketing assets, which included seller financing in the form of a $370 million five-year note and letters of credit totaling $54 million. In addition, we had other dispositions during the year and some assets were classified back into held for use. Also during 2009, we classified additional marketing assets as held for sale. Accordingly, at December 31, 2009, we classified $323 million of noncurrent assets, primarily investments in equity affiliates, as held for sale and most of this amount is included in “Prepaid expenses and other current assets.” We also classified $75 million of noncurrent deferred tax liabilities as current, based on their held for sale status.

Note 6—Investments, Loans and Long-Term Receivables

Components of investments, loans and long-term receivables at December 31 were:

	Millions of Dollars	
	2009	2008
Equity investments	**$ 34,730**	29,914
Loans and advances—related parties	**2,352**	1,973
Long-term receivables	**1,009**	597
Other investments	**453**	415
	$ 38,544	32,899

Equity Investments

Affiliated companies in which we have a significant equity investment include:

- Australia Pacific LNG—50 percent owned joint venture with Origin Energy—to develop coalbed methane production from the Bowen and Surat Basins in Queensland, Australia, as well as process and export LNG.
- FCCL Partnership—50 percent owned business venture with Cenovus Energy Inc.—produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend.
- WRB Refining LLC—50 percent owned business venture with Cenovus—owns the Wood River and Borger Refineries, which process crude oil into refined products.
- OAO LUKOIL—20 percent ownership interest—explores for and produces crude oil, natural gas and natural gas liquids; refines, markets and transports crude oil and petroleum products; and is headquartered in Russia.
- OOO Naryanmarneftegaz (NMNG)—30 percent ownership interest and a 50 percent governance interest—a joint venture with LUKOIL to explore for, develop and produce oil and gas resources in the northern part of Russia's Timan-Pechora province.
- DCP Midstream, LLC—50 percent owned joint venture with Spectra Energy—owns and operates gas plants, gathering systems, storage facilities and fractionation plants.
- Chevron Phillips Chemical Company LLC (CPChem)—50 percent owned joint venture with Chevron Corporation—manufactures and markets petrochemicals and plastics.

Summarized 100 percent financial information for equity method investments in affiliated companies, combined, was as follows (information included for LUKOIL is based on estimates):

	Millions of Dollars		
	2009	2008	2007
Revenues	**$ 128,881**	180,070	143,686
Income before income taxes	**12,121**	22,356	19,807
Net income	**9,145**	17,976	15,229
Current assets	**36,139**	34,838	29,451
Noncurrent assets	**126,163**	114,294	90,939
Current liabilities	**22,483**	21,150	16,882
Noncurrent liabilities	**30,960**	29,845	26,656

Our share of income taxes incurred directly by the equity companies is reported in equity in earnings of affiliates, and as such is not included in income taxes in our consolidated financial statements.

At December 31, 2009, retained earnings included $1,504 million related to the undistributed earnings of affiliated companies. Distributions received from affiliates were $2,882 million, $3,259 million and $3,326 million in 2009, 2008 and 2007, respectively.

Australia Pacific LNG

In October 2008, we closed on a transaction with Origin Energy, an integrated Australian energy company, to further enhance our long-term Australasian natural gas business. The 50/50 joint venture, Australia Pacific LNG (APLNG) is focused on coalbed methane production from the Bowen and Surat Basins in Queensland, Australia, and LNG processing and export sales. This transaction gives us access to coalbed methane resources in Australia and enhances our LNG position with the expected creation of an additional LNG hub targeting the Asia Pacific markets.

Under the terms of the transaction, we paid $5 billion at closing, which after the effect of hedging gains, resulted in an initial cash acquisition cost of $4.7 billion. In addition, we are responsible for AU$1.15 billion related to Origin's initial share of joint venture funding requirements, as incurred. We have committed to make up to four additional payments of $500 million each, expected within the next decade, conditional on up to four LNG trains being approved by the joint venture for development.

At December 31, 2009, the book value of our equity method investment in APLNG was $7,344 million, which includes $2,196 million of cumulative translation effects due to a strengthening Australian dollar. Our 50 percent share of the historical cost basis net assets of APLNG on its books under U.S. generally accepted accounting principles (GAAP) was $659 million, resulting in a basis difference of $6,698 million on our books. The amortizable portion of the basis difference, $4,692 million associated with properties, plants and equipment, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, most of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture begins producing natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income attributable to ConocoPhillips for 2009 and 2008 was after-tax expense of $4 million and $7 million, respectively, representing the amortization of this basis difference on currently producing licenses.

FCCL and WRB

In January 2007, we closed on a business venture with EnCana Corporation (now Cenovus) to create an integrated North American heavy oil business. The transaction consists of two 50/50 business ventures, a Canadian upstream general partnership, FCCL Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. We use the equity method of accounting for both entities, with the operating results of our investment in FCCL reflecting its use of the full-cost method of accounting for oil and gas exploration and development activities.

At December 31, 2009, the book value of our investment in FCCL was $8,318 million. FCCL's operating assets consist of the Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. Cenovus is the operator and managing partner of FCCL. We are obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period that began in 2007. For additional information on this obligation, see Note 13—Joint Venture Acquisition Obligation.

At December 31, 2009, the book value of our investment in WRB was $2,975 million. WRB's operating assets consist of the Wood River and Borger Refineries, located in Roxana, Illinois, and Borger, Texas, respectively. As a result of our contribution of these two assets to WRB, a basis difference was created due to the fair value of the contributed assets recorded by WRB exceeding their historical book value. The difference is primarily amortized and recognized as a benefit evenly over a period of 25 years, which is the estimated remaining useful life of the refineries at the closing date. The basis difference at December 31, 2009, was $4,344 million. Equity earnings in 2009, 2008 and 2007 were increased by $209 million, $246 million and $202 million, respectively, due to amortization of the basis difference. We are the operator and managing partner of WRB. Cenovus is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period that began in 2007. For the Wood River Refinery, operating results are shared 50/50 starting upon formation. For the Borger Refinery, we were entitled to 85 percent of the operating results in 2007, with our share decreasing to 65 percent in 2008, and 50 percent in all years thereafter.

LUKOIL

LUKOIL is an integrated energy company headquartered in Russia, with operations worldwide. Our ownership interest was 20 percent at December 31, 2009, 2008 and 2007, based on 851 million shares authorized and issued. For financial reporting under U.S. GAAP, treasury shares held by LUKOIL are not considered outstanding for determining our equity method ownership interest in LUKOIL. Our ownership interest, based on estimated shares outstanding at December 31, 2009, 2008 and 2007, was 20.09 percent, 20.06 percent and 20.6 percent, respectively.

Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity earnings for our LUKOIL investment are estimated, based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results.

Since the inception of our investment and through June 30, 2008, the market value of our investment in LUKOIL exceeded book value, based on the price of LUKOIL American Depositary Receipts (ADRs) on the London Stock Exchange. However, the price of LUKOIL ADRs experienced significant decline during the second half of 2008, and traded for most of the fourth quarter and into early 2009 in the general range of $25 to $40 per share. The ADR price ended the year at $32.05 per share, or 67 percent lower than the June 30, 2008, price. This resulted in a December 31, 2008, market value of our investment of $5,452 million, or 58 percent lower than our book value. Based on a review of the facts and circumstances surrounding this decline in the market value of our investment during the second half of 2008, we concluded that an impairment of our investment was necessary. In reaching this conclusion, we considered the length of time market value has been below book value and the severity of the decline in market value to be important factors. In combination, these two items caused us to conclude that the decline was other than temporary.

Accordingly, we recorded a noncash $7,410 million, before- and after-tax impairment, in our fourth-quarter 2008 results. This impairment had the effect of reducing our book value to $5,452 million, based on the market value of LUKOIL ADRs on December 31, 2008.

At December 31, 2009, the book value of our investment in LUKOIL was $6,861 million. Our 20 percent share of the net assets of LUKOIL was estimated to be $11,314 million. This negative basis difference of $4,453 million is primarily being amortized on a straight-line basis over a 22-year useful life as an increase to equity earnings. Equity earnings in 2009 were increased $209 million, while equity earnings in 2008 and 2007 were reduced $88 million and $77 million, respectively, due to amortization of the positive basis difference that existed prior to the 2008 year-end investment impairment. On December 31, 2009, the closing price of LUKOIL shares on the London Stock Exchange was $57.30 per share, making the aggregate total market value of our LUKOIL investment $9,747 million.

NMNG

NMNG is a joint venture with LUKOIL, created in June 2005, to develop resources in the northern part of Russia's Timan-Pechora province. We have a 30 percent direct ownership interest with a 50 percent governance interest. At December 31, 2009, the book value of our equity method investment in NMNG was $1,647 million. NMNG is nearing completion of the development of the YK Field, which achieved initial production in June 2008. Production from the NMNG joint venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. During 2009, we reduced the carrying value of our NMNG investment, reflecting an other-than-temporary decline in fair value primarily attributable to lower probable resources in the YK area.

DCP Midstream

DCP Midstream owns and operates gas plants, gathering systems, storage facilities and fractionation plants. At December 31, 2009, the book value of our equity method investment in DCP Midstream was $1,003 million. DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues until December 31, 2014. Beginning in 2015, the volume commitment is reduced by 20 percent each year until the volume commitment is zero. This purchase commitment is on an "if-produced, will-purchase" basis and so has no fixed production schedule, but has had, and is expected over the remaining term of the contract to have, a relatively stable purchase pattern. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees.

CPChem

CPChem manufactures and markets petrochemicals and plastics. At December 31, 2009, the book value of our equity method investment in CPChem was $2,445 million. We have multiple supply and purchase agreements in place with CPChem, ranging in initial terms from one to 99 years, with extension options. These agreements cover sales and purchases of refined products, solvents, and petrochemical and natural gas liquids feedstocks, as well as fuel oils and gases. Delivery quantities vary by product, and are generally on an "if-produced, will-purchase" basis. All products are purchased and sold under specified pricing formulas based on various published pricing indices, consistent with terms extended to third-party customers.

Loans to Related Parties

As part of our normal ongoing business operations and consistent with industry practice, we invest and enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. Included in such activity are loans made to certain affiliated companies. Loans are recorded when cash is transferred to the affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement's stated interest rate. Loans are assessed for impairment when events indicate the loan balance may not be fully recovered.

Significant loans to affiliated companies include the following:

- $707 million in loan financing to Freeport LNG Development, L.P. for the construction of an LNG receiving terminal that became operational in June 2008. Freeport began making repayments in September 2008.
- $278 million in loan financing at December 2009 exchange rates to Varandey Terminal Company associated with the costs of the terminal expansion. The terminal expansion was completed in June 2008, and principal repayments began in April 2009.
- $1,000 million of project financing and an additional $88 million of accrued interest to Qatargas 3, which is an integrated project to produce and liquefy natural gas from Qatar's North Field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, which is expected in 2011, all project loan facilities, including the ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2009, Qatargas 3 had approximately $3.6 billion outstanding under all the loan facilities.
- $350 million of loan financing to WRB Refining LLC to assist it in meeting its operating and capital spending requirements.

The long-term portion of these loans are included in the "Loans and advances—related parties" line on the consolidated balance sheet, while the short-term portion is in "Accounts and notes receivable—related parties."

Other Investments

We have investments remeasured at fair value on a recurring basis to support certain nonqualified deferred compensation plans. The fair value of these assets at December 31, 2009, was $338 million, and substantially the entire value is categorized in Level 1 of the fair value hierarchy. These investments are measured at fair value using a market approach based on quotations from national securities exchanges.

Merey Sweeny, L.P. (MSLP) is a limited partnership that owns a 70,000 barrel-per-day delayed coker and related facilities at the Sweeny Refinery used to produce fuel-grade petroleum coke. Prior to August 28, 2009, MSLP was owned 50/50 by us and Petróleos de Venezuela S.A. (PDVSA). Under the agreements that govern the relationships between the partners, certain defaults by PDVSA with respect to supply of crude oil to the Sweeny Refinery gave us the right to acquire PDVSA's 50 percent ownership interest in MSLP. On August 28, 2009, we exercised that right. In public statements, PDVSA has challenged our actions. We continue to use the equity method of accounting for our investment in MSLP.

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Note 7—Properties, Plants and Equipment

Properties, plants and equipment (PP&E) are recorded at cost. Within the E&P segment, depreciation is mainly on a unit-of-production basis, so depreciable life will vary by field. In the R&M segment, investments in refining manufacturing facilities are generally depreciated on a straight-line basis over a 25-year life, and pipeline assets over a 45-year life. The company's investment in PP&E, with accumulated depreciation, depletion and amortization (Accum. DD&A), at December 31 was:

	Millions of Dollars					
	2009			2008		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$ 115,224**	**45,577**	**69,647**	102,591	35,375	67,216
Midstream	**123**	**74**	**49**	120	70	50
R&M	**23,047**	**6,714**	**16,333**	21,116	5,962	15,154
LUKOIL Investment	**—**	**—**	**—**	—	—	—
Chemicals	**—**	**—**	**—**	—	—	—
Emerging Businesses	**1,198**	**300**	**898**	1,056	293	763
Corporate and Other	**1,650**	**869**	**781**	1,561	797	764
	$ 141,242	**53,534**	**87,708**	126,444	42,497	83,947

Note 8—Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during 2009, 2008 and 2007:

	Millions of Dollars		
	2009	2008	2007
Beginning balance at January 1	**$ 660**	589	537
Additions pending the determination of proved reserves	**342**	160	157
Reclassifications to proved properties	**(39)**	(37)	(58)
Sales of suspended well investment	**(21)**	(10)	(22)
Charged to dry hole expense	**(34)**	(42)	(25)
Ending balance at December 31	**$ 908**	660	589*

* *Includes $7 million related to assets held for sale in 2007.*

The following table provides an aging of suspended well balances at December 31, 2009, 2008 and 2007:

	Millions of Dollars		
	2009	2008	2007
Exploratory well costs capitalized for a period of one year or less	**$ 319**	182	153
Exploratory well costs capitalized for a period greater than one year	**589**	478	436
Ending balance	**$ 908**	660	589
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**34**	31	35

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2009:

	Millions of Dollars			
		Suspended Since		
Project	Total	2007-2008	2004-2006	2001-2003
Aktote—Kazakhstan *(2)*	$ 17	—	7	10
Alpine satellite—Alaska *(2)*	23	—	—	23
Caldita/Barossa—Australia *(1)*	77	—	77	—
Clair—U.K. *(2)*	48	31	17	—
Fiord West—Alaska *(1)*	16	16	—	—
Harrison—U.K. *(2)*	16	16	—	—
Jasmine—U.K. *(2)*	72	47	25	—
Kairan—Kazakhstan *(2)*	26	13	13	—
Kashagan—Kazakhstan *(1)*	34	25	—	9
Malikai—Malaysia *(2)*	48	—	48	—
Petai/Pisagon—Malaysia *(1)*	19	10	9	—
Saleski—Canada *(1)*	13	13	—	—
Sunrise 3—Australia *(2)*	13	13	—	—
Surmont—Canada *(1)*	23	15	8	—
Thornbury—Canada *(1)*	19	19	—	—
Ubah—Malaysia *(1)*	22	22	—	—
Uge—Nigeria *(2)*	30	16	14	—
Seventeen projects of less than $10 million each *(1)(2)*	73	37	30	6
Total of 34 projects	$ 589	293	248	48

(1) Additional appraisal wells planned.

(2) Appraisal drilling complete; costs being incurred to assess development.

Note 9—Goodwill and Intangibles

Goodwill

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars					
	2009			2008		
	E&P	R&M	Total	E&P	R&M	Total
Balance as of January 1						
Goodwill	**$ 25,443**	**3,778**	**29,221**	25,569	3,767	29,336
Accumulated impairment losses	**(25,443)**	**—**	**(25,443)**	—	—	—
	—	**3,778**	**3,778**	25,569	3,767	29,336
Goodwill allocated to assets held for sale or sold	**—**	**(135)**	**(135)**	(148)	—	(148)
Goodwill impairment	**—**	**—**	**—**	(25,443)	—	(25,443)
Tax and other adjustments	**—**	**(5)**	**(5)**	22	11	33
Balance as of December 31						
Goodwill	**25,443**	**3,638**	**29,081**	25,443	3,778	29,221
Accumulated impairment losses	**(25,443)**	**—**	**(25,443)**	(25,443)	—	(25,443)
	$ —	**3,638**	**3,638**	—	3,778	3,778

Goodwill Impairment

We perform our annual goodwill impairment review in the fourth quarter of each year. During the fourth quarter of 2008, there were severe disruptions in the credit markets and reductions in global economic activity which had significant adverse impacts on stock markets and oil-and-gas-related commodity prices, both of which contributed to a significant decline in our company's stock price and corresponding market capitalization. For most of the fourth quarter, our market capitalization value was significantly below the recorded net book value of our balance sheet, including goodwill.

Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of these reporting units for purposes of performing the annual goodwill impairment test. Management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to our market capitalization. We use an average of our market capitalization over the 30 calendar days preceding the impairment testing date as being more reflective of our stock price trend than a single day, point-in-time market price. Because, in our judgment, Worldwide E&P is considered to have a higher valuation volatility than Worldwide R&M, the long-term free cash flow growth rate implied from this reconciliation to our recent average market capitalization is applied to the Worldwide E&P net present value calculation.

The accounting principles regarding goodwill acknowledge that the observed market prices of individual trades of a company's stock (and thus its computed market capitalization) may not be representative of the fair value of the company as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity's individual common stock. In most industries, including ours, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above net present value calculations have been determined, we also add a control premium to the calculations. This control premium is judgmental and is based on observed acquisitions in our industry. The resultant fair values calculated for the reporting units are then compared to observable metrics on large mergers and acquisitions in our industry to determine whether those valuations, in our judgment, appear reasonable.

After determining the fair values of our various reporting units as of December 31, 2008, it was determined that our Worldwide R&M reporting unit passed the first step of the goodwill impairment test, while our Worldwide E&P reporting unit did not pass the first step. As described above, the second step of the goodwill impairment test uses the estimated fair value of Worldwide E&P from the first step as the purchase price in a hypothetical acquisition of the reporting unit. The significant hypothetical purchase price allocation adjustments made to the assets and liabilities of Worldwide E&P in this second step calculation were in the areas of:

- Adjusting the carrying value of major equity method investments to their estimated fair values.
- Adjusting the carrying value of properties, plants and equipment (PP&E) to the estimated aggregate fair value of all oil and gas property interests.
- Recalculating deferred income taxes under FASB ASC Topic 740, "Income Taxes," after considering the likely tax basis a hypothetical buyer would have in the assets and liabilities.

When determining the above adjustment for the estimated aggregate fair value of PP&E, it was noted that in order for any residual purchase price to be allocated to goodwill, the purchase price assigned to PP&E would have to be well below the value of the PP&E implied by recently-observed metrics from other sales of major oil and gas properties.

Based on the above analysis, we concluded that a $25.4 billion before- and after-tax noncash impairment of the entire amount of recorded goodwill for the Worldwide E&P reporting unit was required. This impairment was recorded in the fourth quarter of 2008.

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Intangible Assets

Information on the carrying value of intangible assets follows:

	Millions of Dollars		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets			
Balance at December 31, 2009			
Technology related	**$ 126**	**(74)**	**52**
Refinery air permits	**14**	**(13)**	**1**
Contract based	**87**	**(65)**	**22**
Other	**37**	**(29)**	**8**
	$ 264	**(181)**	**83**
Balance at December 31, 2008			
Technology related	$ 120	(60)	60
Refinery air permits	14	(10)	4
Contract based	116	(81)	35
Other	36	(27)	9
	$ 286	(178)	108
Indefinite-Lived Intangible Assets			
Balance at December 31, 2009			
Trade names and trademarks			**$ 494**
Refinery air and operating permits			**246**
			$ 740
Balance at December 31, 2008			
Trade names and trademarks			$ 494
Refinery air and operating permits			244
			$ 738

Amortization expense related to the intangible assets above for the years ended December 31, 2009 and 2008, was $30 million and $35 million, respectively. Estimated 2010 amortization expense is $25 million. Amortization expense is expected to be approximately $20 million and $10 million per year during 2011 and 2012, respectively, and approximately $5 million per year during 2013 and 2014.

Note 10—Impairments

Goodwill

See the “Goodwill Impairment” section of Note 9—Goodwill and Intangibles, for information on the complete impairment of our E&P segment goodwill.

LUKOIL

See the “LUKOIL” section of Note 6—Investments, Loans and Long-Term Receivables, for information on the impairment of our LUKOIL investment.

Expropriated Assets

Ecuador

In April 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before the World Bank’s International Centre for Settlement of Investment Disputes (ICSID) against The Republic of Ecuador and PetroEcuador as a result of the newly-enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by the ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. As a result, our assets in Ecuador were effectively expropriated. Accordingly, in the second quarter of 2009, we recorded a noncash charge of $51 million before- and after-tax related to the full impairment of our exploration and production investments in Ecuador. In the third quarter of 2009, Ecuador took over operations in Block 7 and 21, formalizing the complete expropriation of our assets. A jurisdictional hearing before the ICSID was held in January 2010, with the outcome still pending.

Venezuela

On January 31, 2007, Venezuela's National Assembly passed a law allowing the president of Venezuela to pass laws on certain matters by decree. On February 26, 2007, the president of Venezuela issued a decree (the Nationalization Decree) mandating the termination of the then-existing structures related to our heavy oil ventures and oil production risk contracts and the transfer of all rights relating to our heavy oil ventures and oil production risk contracts to joint ventures ("*empresas mixtas*") that will be controlled by the Venezuelan national oil company or its subsidiaries.

On June 26, 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Nationalization Decree. In response, Petróleos de Venezuela S.A. (PDVSA) or its affiliates directly assumed the activities associated with ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro oil development project. Based on Venezuelan statements that the expropriation of our oil interests in Venezuela occurred on June 26, 2007, management determined such expropriation required a complete impairment, under U.S. generally accepted accounting principles, of our investments in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro oil development project. Accordingly, we recorded a noncash impairment, including allocable goodwill, of $4,588 million before-tax ($4,512 million after-tax) in the second quarter of 2007.

The impairment included equity method investments and properties, plants and equipment. Also, this expropriation of our oil interests is viewed as a partial disposition of our Worldwide E&P reporting unit and required an allocation of goodwill to the expropriation event. The amount of goodwill impaired as a result of this allocation was $1,925 million.

We filed a request for international arbitration on November 2, 2007, with the ICSID, an arm of the World Bank. The request was registered by the ICSID on December 13, 2007. The tribunal of three arbitrators is constituted, and the arbitration proceeding is under way.

We believe the value of our expropriated Venezuelan oil operations substantially exceeds the historical cost-based carrying value plus goodwill allocable to those operations. However, U.S. generally accepted accounting principles require a claim that is the subject of litigation be presumed to not be probable of realization. In addition, the timing of any negotiated or arbitrated settlement is not known at this time, but we anticipate it could take years. Accordingly, any compensation for our expropriated assets was not considered when making the impairment determination, since to do so could result in the recognition of compensation for the expropriation prior to its realization.

Other Impairments

During 2009, 2008 and 2007, we recognized the following before-tax impairment charges, excluding the goodwill, LUKOIL investment and expropriated assets impairments noted above:

	Millions of Dollars		
	2009	2008	2007
E&P			
United States	**$ 5**	620	73
International	**412**	173	398
R&M			
United States	**63**	534	66
International	**3**	181	25
Increase in fair value of previously impaired assets	**—**	—	(128)
Emerging Businesses	**—**	130	—
Corporate	**1**	48	8
	$ 484	1,686	442

2009

During 2009, we recorded property impairments of $417 million in our E&P segment, primarily as a result of lower natural gas price assumptions, reduced volume forecasts, and higher royalty, operating cost and capital expenditure assumptions. We also recorded property impairments of $66 million in our R&M segment, primarily associated with planned asset dispositions.

The following table shows the values of assets at December 31, 2009, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	Millions of Dollars			
		Fair Value Measurements Using		2009
	Fair Value	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Net properties, plants and equipment (held for use)	$ 210	—	210	385
Net properties, plants and equipment (held for sale)	91	35	56	62
Equity method investments	1,784	—	1,784	286

Net properties, plants and equipment held for use with a carrying amount of $610 million were written down to a fair value of $210 million, resulting in a before-tax loss of $385 million (including impact of exchange rates). The fair values were determined by the application of an internal discounted cash flow model using estimates of future production, prices and a discount rate believed to be consistent with those used by principal market participants.

During the year, net properties, plants and equipment held for sale with a carrying amount of $178 million were written down to a fair value of $121 million ($91 million still unsold at year end), less cost to sell of $5 million for a net $116 million, resulting in a before-tax loss of $62 million. The fair values were largely based on binding negotiated prices with third parties, with some adjusted for the fair value of certain liabilities retained.

At December 31, 2009 certain equity method investments associated with our E&P segment were determined to have a fair value below carrying amount and the impairment was considered to be other than temporary. As a result, those investments with a book value of $2,070 million were written down to a fair value of $1,784 million resulting in a charge of $286 million before-tax, which is included in the “Equity in earnings of affiliates” line of the consolidated statement of operations. The fair values were determined by the application of an internal discounted cash flow model using estimates of future production, prices and a discount rate believed to be consistent with those used by principal market participants, as well as reference to market analysis of certain similar undeveloped properties owned by one of the investees.

2008
As a result of the economic downturn in the fourth quarter of 2008, the outlook for crude oil and natural gas prices, refining margins, and power spreads sharply deteriorated. In addition, current project economics in our E&P segment resulted in revised capital spending plans. Because of these factors, certain E&P, R&M and Emerging Businesses properties no longer passed the undiscounted cash flow tests and had to be written down to fair value. Consequently, we recorded property impairments of approximately $1,480 million, primarily consisting of various producing fields in the U.S. Lower 48 and Canada, one U.S. and one European refinery and a U.S. power generation facility. In addition, we recorded property impairments for increased asset retirement obligations, vacant office buildings in the United States and canceled R&M capital projects.

2007
During 2007, we recorded property impairments of $257 million associated with planned asset dispositions in our E&P and R&M segments. E&P also recorded additional property impairments in 2007 resulting from increased asset retirement obligations, downward reserve revisions and higher projected operating costs for certain fields in North America and the United Kingdom and an abandoned project in Alaska. R&M recorded additional property impairments associated with various terminals and pipelines, primarily in the United States. Also, we reported a $128 million benefit in 2007 for the subsequent increase in the fair value of certain assets impaired in the prior year, primarily to reflect finalized sales agreements. This gain was included in the “Impairments—Other” line of the consolidated statement of operations.

Note 11—Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

	Millions of Dollars	
	2009	2008
Asset retirement obligations	**$ 8,295**	6,615
Accrued environmental costs	**1,017**	979
Total asset retirement obligations and accrued environmental costs	**9,312**	7,594
Asset retirement obligations and accrued environmental costs due within one year*	**(599)**	(431)
Long-term asset retirement obligations and accrued environmental costs	**$ 8,713**	7,163

* *Classified as a current liability on the balance sheet, under the caption “Other accruals.” Includes $14 million related to assets held for sale in 2008.*

Asset Retirement Obligations

We are required to record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related properties, plants and equipment. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

We have numerous asset removal obligations that we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries.

During 2009 and 2008, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2009	2008
Balance at January 1	**$ 6,615**	6,613
Accretion of discount	**394**	389
New obligations	**113**	123
Changes in estimates of existing obligations	**905**	994
Spending on existing obligations	**(322)**	(217)
Property dispositions	**(82)**	(115)
Foreign currency translation	**672**	(1,172)
Balance at December 31	**$ 8,295**	6,615

Accrued Environmental Costs

Total environmental accruals at December 31, 2009 and 2008, were $1,017 million and $979 million, respectively. The 2009 increase in total accrued environmental costs is due to new accruals, accrual adjustments and accretion exceeding payments during the year on accrued environmental costs.

We had accrued environmental costs of $632 million and $652 million at December 31, 2009 and 2008, respectively, primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by Canada and the state of Alaska at exploration and production sites. We had also accrued in Corporate and Other $292 million and $234 million of environmental costs associated with nonoperator sites at December 31, 2009 and 2008, respectively. In addition, $93 million was included at both December 31, 2009 and 2008, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities will be paid over periods extending up to 30 years.

Because a large portion of the accrued environmental costs were acquired in various business combinations, they are discounted obligations. Expected expenditures for acquired environmental obligations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $627 million at December 31, 2009. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $90 million in 2010, $87 million in 2011, $67 million in 2012, $48 million in 2013, $39 million in 2014, and $358 million for all future years after 2014.

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Note 12—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2009	2008
9.875% Debentures due 2010	**$ 150**	150
9.375% Notes due 2011	**328**	328
9.125% Debentures due 2021	**150**	150
8.75% Notes due 2010	**1,264**	1,264
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**23**	30
7.65% Debentures due 2023	**88**	88
7.625% Debentures due 2013	**100**	100
7.40% Notes due 2031	**500**	500
7.375% Debentures due 2029	**92**	92
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.68% Notes due 2011	**400**	400
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2011	**500**	500
6.50% Notes due 2039	**2,250**	—
6.50% Notes due 2039	**500**	—
6.40% Notes due 2011	**178**	178
6.375% Notes due 2009	**—**	284
6.35% Notes due 2011	**1,750**	1,750
6.00% Notes due 2020	**1,000**	—
5.951% Notes due 2037	**645**	645
5.95% Notes due 2036	**500**	500
5.90% Notes due 2032	**505**	505
5.90% Notes due 2038	**600**	600
5.75% Notes due 2019	**2,250**	—
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.30% Notes due 2012	**350**	350
5.20% Notes due 2018	**500**	500
4.75% Notes due 2012	**897**	897
4.75% Notes due 2014	**1,500**	—
4.60% Notes due 2015	**1,500**	—
4.40% Notes due 2013	**400**	400
Commercial paper at 0.06% — 0.29% at year-end 2009 and 1.05% — 1.76% at year-end 2008	**1,300**	6,933
Floating Rate Five-Year Term Note due 2011 at 0.45% at year-end 2009 and 1.638% at year-end 2008	**750**	1,500
Floating Rate Notes due 2009 at 4.42% at year-end 2008	**—**	950
Industrial Development Bonds due 2012 through 2038 at 0.24% — 5.75% at year-end 2009 and 0.93% — 5.75% at year-end 2008	**252**	252
Guarantee of savings plan bank loan payable due 2015 at 2.01% at year-end 2009 and 2.46% at year-end 2008	**103**	140
Note payable to Merey Sweeny, L.P. due 2020 at 7% (related party)	**154**	163
Marine Terminal Revenue Refunding Bonds due 2031 at 0.26% — 0.40% at year-end 2009 and 0.40% — 1.00% at year-end 2008	**265**	265
Other	**38**	36
Debt at face value	**28,120**	26,788
Capitalized leases	**31**	28
Net unamortized premiums and discounts	**502**	639
Total debt	**28,653**	27,455
Short-term debt	**(1,728)**	(370)
Long-term debt	**$ 26,925**	27,085

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2010 through 2014 are: $1,728 million, $3,972 million, $2,345 million, $1,277 million and $1,532 million, respectively. At December 31, 2009, we had classified $1,060 million of short-term debt as long-term debt, based on our ability and intent to refinance the obligation on a long-term basis under our revolving credit facilities.

In February 2009, we issued $1.5 billion of 4.75% Notes due 2014, $2.25 billion of 5.75% Notes due 2019, and $2.25 billion of 6.50% Notes due 2039, and in May 2009, we issued $1.5 billion of 4.60% Notes due 2015, $1.0 billion of 6.00% Notes due 2020 and an additional $500 million of 6.50% Notes due 2039. The proceeds from the notes were primarily used to reduce outstanding commercial paper balances and for general corporate purposes.

During 2009, we used proceeds from the issuance of commercial paper to redeem $284 million of 6.375% Notes and $950 million of Floating Rate Notes upon their maturity, and prepaid $750 million of Floating Rate Five-Year Term Notes.

At December 31, 2009, we had two revolving credit facilities totaling $7.85 billion, consisting of a $7.35 billion facility expiring in September 2012 and a $500 million facility expiring in July 2012. Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, or as support for our commercial paper programs. The revolving credit facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The facility agreements contain a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or by any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreements call for commitment fees on available, but unused, amounts. The agreements also contain early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have two commercial paper programs: the ConocoPhillips $6.35 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, which is used to fund commitments relating to the Qatargas 3 Project. Commercial paper maturities are generally limited to 90 days. At both December 31, 2009 and 2008, we had no direct outstanding borrowings under the revolving credit facilities, but $40 million in letters of credit had been issued. In addition, under the two commercial paper programs, there was $1,300 million of commercial paper outstanding at December 31, 2009, compared with $6,933 million at December 31, 2008. Since we had $1,300 million of commercial paper outstanding and had issued $40 million of letters of credit, we had access to $6.5 billion in borrowing capacity under our revolving credit facilities at December 31, 2009.

Note 13—Joint Venture Acquisition Obligation

On January 3, 2007, we closed on a business venture with EnCana Corporation (now Cenovus). As a part of the transaction, we are obligated to contribute $7.5 billion, plus interest, over a 10-year period that began in 2007, to the upstream business venture, FCCL Partnership, formed as a result of the transaction. An initial cash contribution of $188 million was made upon closing in January of 2007, and was included in the "Capital expenditures and investments" line on our consolidated statement of cash flows.

Quarterly principal and interest payments of $237 million began in the second quarter of 2007, and will continue until the balance is paid. Of the principal obligation amount, approximately $660 million was short-term and was included in the "Accounts payable—related parties" line on our December 31, 2009, consolidated balance sheet. The principal portion of these payments, which totaled $625 million in 2009, is included in the "Other" line in the financing activities section of our consolidated statement of cash flows. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as a capital contribution and is included in the "Capital expenditures and investments" line on our consolidated statement of cash flows.

Note 14—Guarantees

At December 31, 2009, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability either because the guarantees were issued prior to December 31, 2002, or because the fair value of the obligation is immaterial. In addition, unless otherwise stated we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

Construction Completion Guarantees

- In December 2005, we issued a construction completion guarantee for 30 percent of the $4 billion in loan facilities of Qatargas 3, which are being used to finance the construction of an LNG train in Qatar. Of the $4 billion in loan facilities, we committed to provide $1.2 billion. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $850 million, which could become payable if the full debt financing is utilized and completion of the Qatargas 3 Project is not achieved. The project financing will be nonrecourse to ConocoPhillips upon certified completion, expected in 2011. At December 31, 2009, the carrying value of the guarantee to third-party lenders was $11 million.

Guarantees of Joint Venture Debt

- In June 2006, we issued a guarantee for our ownership percentage of $2 billion in credit facilities of Rockies Express Pipeline LLC, operated by Kinder Morgan Energy Partners, L.P. At December 31, 2009, Rockies Express had $1,673 million outstanding under the credit facilities, with our 25 percent guarantee equaling $418 million. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $500 million, which could become payable if the credit facilities are fully utilized and Rockies Express fails to meet its obligations under the credit agreement. The guarantee expires in April 2011. At December 31, 2009, the total carrying value of this guarantee to third-party lenders was $11 million.
- At December 31, 2009, we had guarantees outstanding for our portion of joint venture debt obligations, which have terms of up to 16 years. The maximum potential amount of future payments under the guarantees is approximately $80 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

- In conjunction with our purchase of a 50 percent ownership interest in APLNG from Origin Energy in October 2008, we agreed to participate, if and when requested, in any parent company guarantees that were outstanding at the time we purchased our interest in APLNG. These parent company guarantees cover the obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 7 to 22 years. Our maximum potential amount of future payments, or cost of volume delivery, under these guarantees is estimated to be $1,450 million ($3,140 million in the event of intentional or reckless breach) at December 2009 exchange rates based on our 50 percent share of the remaining contracted volumes, which could become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the partners do not make necessary equity contributions into APLNG.
- We have other guarantees with maximum future potential payment amounts totaling $506 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, guarantees to fund the short-term cash liquidity deficits of certain joint ventures, a guarantee of minimum charter revenue for two LNG vessels, one small construction completion guarantee, guarantees relating to the startup of a refining joint venture, guarantees of the lease payment obligations of a joint venture, and guarantees of the residual value of leased corporate aircraft. At December 31,

2009, the carrying value of these guarantees to third-party lenders was $1 million. These guarantees generally extend up to 15 years or life of the venture.

In the third quarter of 2009, we sold our remaining ownership interest in four Keystone Pipeline entities to TransCanada Corporation. As a result, we no longer have any financial guarantees related to Keystone.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. Agreements associated with these sales include indemnifications for taxes, environmental liabilities, permits and licenses, employee claims, real estate indemnity against tenant defaults, and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2009, was $412 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount were $258 million of environmental accruals for known contamination that are included in asset retirement obligations and accrued environmental costs at December 31, 2009. For additional information about environmental liabilities, see Note 15—Contingencies and Commitments.

Note 15—Contingencies and Commitments

In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the case of income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 20—Income Taxes, for additional information about income-tax-related contingencies.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental

We are subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management’s best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. If we were solely responsible, the costs, in some cases, could be material to our results of operations, capital resources or liquidity, or to those of one of our segments. However, settlements and costs incurred in matters that previously have been resolved have not been material to our results of operations or financial condition. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly.

As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit and some of the indemnifications are subject to dollar limits and time limits. We have not recorded accruals for any potential contingent liabilities that we expect to be funded by the prior owners under these indemnifications.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 11—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial, as well as the pace of settlement discussions in individual matters. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization believes there is a remote likelihood future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements.

Other Contingencies

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2009, we had performance obligations secured by letters of credit of $1,624 million (of which $40 million was issued under the provisions of our revolving credit facility, and the remainder was issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business. See Note 10—Impairments, for additional information about expropriated assets in Ecuador and Venezuela and the contingencies related to receiving adequate compensation for our oil interests related to these assets.

Long-Term Throughput Agreements and Take-or-Pay Agreements

We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are: 2010—$88 million; 2011—$88 million; 2012—$84 million; 2013—$83 million; 2014—$84 million; and 2015 and after—$273 million. Total payments under the agreements were $77 million in 2009, $75 million in 2008 and $67 million in 2007.

Note 16—Financial Instruments and Derivative Contracts

Derivative Instruments

We use financial and commodity-based derivative contracts to manage exposures to fluctuations in foreign currency exchange rates, commodity prices, and interest rates, or to capture market opportunities. Since we are not currently using hedge accounting, all gains and losses, realized or unrealized, from derivative contracts have been recognized in the consolidated statement of operations. Gains and losses from derivative contracts held for trading not directly related to our physical business, whether realized or unrealized, have been reported net in other income.

Purchase and sales contracts for commodities that are readily convertible to cash (e.g., crude oil, natural gas and gasoline) are recorded on the balance sheet as derivatives unless the contracts are for quantities we expect to use or sell over a reasonable period in the normal course of business (i.e., contracts eligible for the normal purchases and normal sales exception). We record most of our contracts to buy or sell natural gas and the majority of our contracts to sell power as derivatives, but we do apply the normal purchases and normal sales exception to certain long-term contracts to sell our natural gas production. We generally apply this normal purchases and normal sales exception to eligible crude oil and refined product commodity purchase and sales contracts; however, we may elect not to apply this exception (e.g., when another derivative instrument will be used to mitigate the risk of the purchase or sale contract but hedge accounting will not be applied, in which case both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the balance sheet at fair value).

We value our exchange-cleared derivatives using closing prices provided by the exchange as of the balance sheet date, and these are classified as Level 1 in the fair value hierarchy. Over-the-counter (OTC) financial swaps and physical commodity forward purchase and sale contracts are generally valued using quotations provided by brokers and price index developers such as Platts and Oil Price Information Service. These quotes are corroborated with market data and are classified as Level 2. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, OTC swaps and physical commodity purchase and sale contracts are valued using internally developed methodologies that consider historical relationships among various commodities that result in management's best estimate of fair value. These contracts are classified as Level 3.

Exchange-cleared financial options are valued using exchange closing prices and are classified as Level 1. Financial OTC and physical commodity options are valued using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and contractual prices for the underlying instruments, as well as other relevant economic measures. The degree to which these inputs are observable in the forward markets determines whether the options are classified as Level 2 or 3.

We use a mid-market pricing convention (the mid-point between bid and ask prices). When appropriate, valuations are adjusted to reflect credit considerations, generally based on available market evidence.

The fair value hierarchy for our derivative assets and liabilities accounted for at fair value on a recurring basis was:

	Millions of Dollars							
	December 31, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity derivatives	**$ 1,710**	**1,659**	**61**	**3,430**	4,994	2,874	112	7,980
Foreign exchange derivatives	**—**	**45**	**—**	**45**	—	97	—	97
Total assets	**1,710**	**1,704**	**61**	**3,475**	4,994	2,971	112	8,077
Liabilities								
Commodity derivatives	**(1,797)**	**(1,496)**	**(24)**	**(3,317)**	(5,221)	(2,497)	(72)	(7,790)
Foreign exchange derivatives	**—**	**(47)**	**—**	**(47)**	—	(93)	—	(93)
Total liabilities	**(1,797)**	**(1,543)**	**(24)**	**(3,364)**	(5,221)	(2,590)	(72)	(7,883)
Net assets (liabilities)	**$ (87)**	**161**	**37**	**111**	(227)	381	40	194

The derivative values above are based on analysis of each contract as the fundamental unit of account; therefore, derivative assets and liabilities with the same counterparty are not reflected net where the legal right of offset exists. Gains or losses from contracts in one level may be offset by gains or losses on contracts in another level or by changes in values of physical contracts or positions that are not reflected in the table above.

The fair value of net commodity derivatives classified as Level 3 in the fair value hierarchy changed as follows during 2009 and 2008:

	Millions of Dollars	
	2009	2008
Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
Beginning balance	**$ 40**	(34)
Total gains (losses), realized and unrealized		
Included in earnings	**17**	6
Included in other comprehensive income	**—**	—
Purchases, issuances and settlements	**(60)**	37
Transfers in and/or out of Level 3	**40**	31
Ending balance	**$ 37**	40

The amounts of Level 3 gains (losses) included in earnings were:

	Millions of Dollars					
	2009			2008		
	Other Operating Revenues	Purchased Crude Oil, Natural Gas and Products	Total	Other Operating Revenues	Purchased Crude Oil, Natural Gas and Products	Total
Total gains (losses) included in earnings	**$ 17**	**—**	**17**	11	(5)	6
Change in unrealized gains (losses) relating to assets held at December 31	**$ 13**	**—**	**13**	20	63	83
Change in unrealized gains (losses) relating to liabilities held at December 31	**$ (14)**	**—**	**(14)**	(8)	(64)	(72)

Commodity Derivative Contracts—We operate in the worldwide crude oil, refined product, natural gas, natural gas liquids and electric power markets and are exposed to fluctuations in the prices for these commodities. These fluctuations can affect our revenues, as well as the cost of operating, investing and financing activities. Generally, our policy is to remain exposed to the market prices of commodities. However, we use futures, forwards, swaps and options in various markets to balance physical systems, meet customer needs, manage price exposures on specific transactions, and do a limited, immaterial amount of trading not directly related to our physical business. These activities may move our risk profile away from market average prices.

The fair value of commodity derivative assets and liabilities at December 31, 2009, and the line items where they appear on our consolidated balance sheet were:

	Millions of Dollars
Assets	
Prepaid expenses and other current assets	$ 3,084
Other assets	359
Liabilities	
Other accruals	3,006
Other liabilities and deferred credits	324

Hedge accounting has not been used for any items in the table unless specified otherwise. The amounts shown are presented gross (i.e., without netting assets and liabilities with the same counterparty where the right of offset and intent to net exist).

The gains (losses) from commodity derivatives incurred during 2009, and the line items where they appear on our consolidated statement of operations were:

	Millions of Dollars
Sales and other operating revenues	$ 1,964
Other income	19
Purchased crude oil, natural gas and products	(2,624)

Hedge accounting has not been used for any items in the table unless specified otherwise.

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The table below summarizes our material net exposures as of December 31, 2009, resulting from outstanding commodity derivative contracts. These financial and physical derivative contracts are primarily used to manage price exposure on our underlying operations. The underlying exposures may be from non-derivative positions such as inventory volumes or firm natural gas transport contracts. Financial derivative contracts may also offset physical derivative contracts, such as forward sales contracts.

	Open Position Long / (Short)
Commodity	
Crude oil, refined products and natural gas liquids (millions of barrels)	(16)
Natural gas and power (billions of cubic feet)	
Fixed price	(60)
Basis	154

Currency Exchange Rate Derivative Contracts—We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to movements in currency exchange rates, although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates to be remitted within the coming year.

The fair value of foreign currency derivative assets and liabilities open at December 31, 2009, and the line items where they appear on our consolidated balance sheet were:

	Millions of Dollars
Assets	
Prepaid expenses and other current assets	$ 38
Other assets	7
Liabilities	
Other accruals	40
Other liabilities and deferred credits	7

Hedge accounting has not been used for any items in the table unless specified otherwise. The amounts shown are presented gross.

Gains and losses from foreign currency derivatives at December 31, 2009, and the line item where they appear on our consolidated statement of operations were:

	Millions of Dollars
Foreign currency transaction (gains) losses	$ (121)

Hedge accounting has not been used for any items in the table unless specified otherwise.

As of December 31, 2009, we had the following net position of outstanding foreign currency swap contracts, entered into primarily to hedge price exposure in our international operations.

	In Millions Notional*	
Foreign Currency Swaps		
Sell U.S. dollar, buy other currencies**	USD	3,211
Buy British pound, sell euro	EUR	267

* *Denominated in U.S. dollars (USD) and euros (EUR).*

** *Primarily euro, Canadian dollar, Norwegian krone and British pound.*

Credit Risk

Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, over-the-counter derivative contracts and trade receivables. Our cash equivalents are placed in high-quality commercial paper, money market funds and time deposits with major international banks and financial institutions.

The credit risk from our over-the-counter derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction, typically a major bank or financial institution. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange or the ICE Futures.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments, and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral.

The aggregate fair value of all derivative instruments with such credit-risk-related contingent features that were in a liability position on December 31, 2009, was $381 million, for which no collateral was posted. If our credit rating were lowered one level from its “A” rating (per Standard and Poor’s) on December 31, 2009, we would be required to post no additional collateral to our counterparties. If we were downgraded below investment grade, we would be required to post $381 million of additional collateral, either with cash or letters of credit.

Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable: The carrying amount reported on the balance sheet approximates fair value.
- Investment in LUKOIL shares: See Note 6—Investments, Loans and Long-Term Receivables, for a discussion of the carrying value and fair value of our investment in LUKOIL shares.
- Debt: The carrying amount of our floating-rate debt approximates fair value. The fair value of the fixed-rate debt is estimated based on quoted market prices.
- Fixed-rate 5.3 percent joint venture acquisition obligation: Fair value is estimated based on the net present value of the future cash flows, discounted at a December 31 effective yield rate of 2.63 percent, based on yields of U.S. Treasury securities of similar average duration adjusted for our average credit risk spread and the amortizing nature of the obligation principal. See Note 13—Joint Venture Acquisition Obligation, for additional information.
- Swaps: Fair value is estimated based on forward market prices and approximates the exit price at period end. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.

- Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange, the ICE Futures, or other traded exchanges.
- Forward-exchange contracts: Fair value is estimated by comparing the contract rate to the forward rate in effect on December 31 and approximates the exit price at that date.

Certain of our commodity derivative and financial instruments at December 31 were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2009	2008	**2009**	2008
Financial assets				
Foreign currency derivatives	**$ 45**	160	**45**	160
Commodity derivatives	**823**	1,279	**823**	1,279
Financial liabilities				
Total debt, excluding capital leases	**28,622**	27,427	**30,565**	26,906
Joint venture acquisition obligation	**5,669**	6,294	**6,276**	6,294
Foreign currency derivatives	**47**	155	**47**	155
Commodity derivatives	**632**	881	**632**	881

The amounts shown for derivatives in the preceding table are presented net (i.e., assets and liabilities with the same counterparty are netted where the right of offset and intent to net exist). In addition, the 2009 commodity derivative assets and liabilities appear net of $70 million of obligations to return cash collateral and $148 million of rights to reclaim cash collateral, respectively. The 2008 commodity derivative assets and liabilities appear net of $123 million of obligations to return cash collateral and $332 million of rights to reclaim cash collateral, respectively. No collateral was deposited or held for the foreign currency derivatives.

Note 17—Equity

Common Stock

The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

	Shares		
	2009	2008	2007
Issued			
Beginning of year	**1,729,264,859**	1,718,448,829	1,705,502,609
Distributed under benefit plans	**4,080,699**	10,816,030	12,946,220
End of year	**1,733,345,558**	1,729,264,859	1,718,448,829
Held in Treasury			
Beginning of year	**208,346,815**	104,607,149	15,061,613
Repurchase of common stock	**—**	103,739,666	89,545,536
End of year	**208,346,815**	208,346,815	104,607,149
Held in Grantor Trusts			
Beginning of year	**40,739,129**	42,411,331	44,358,585
Distributed under benefit plans	**(2,018,692)**	(1,668,456)	(1,856,224)
Repurchase of common stock	**—**	(13,600)	(177,110)
Other	**21,824**	9,854	86,080
End of year	**38,742,261**	40,739,129	42,411,331

Preferred Stock

We have 500 million shares of preferred stock authorized, par value $.01 per share, none of which was issued or outstanding at December 31, 2009 or 2008.

Noncontrolling Interests

At December 31, 2009 and 2008, we had outstanding $590 million and $1,100 million, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. The decrease from 2008 was primarily due to Ashford Energy Capital S.A., a wholly owned consolidated subsidiary, redeeming for $500 million, plus accrued dividends, the investment in Ashford held by Cold Spring Finance S.a.r.l. in the third quarter of 2009. The difference between the redemption amount and the carrying value of the investment was $12 million. The redemption amount was included as a cash outflow in the “Other” line in the financing activities section of our consolidated statement of cash flows.

The remaining noncontrolling interest amounts are primarily related to operating joint ventures we control. The largest of these, amounting to $565 million at December 31, 2009, and $580 million at December 31, 2008, was related to Darwin LNG operations, located in Australia’s Northern Territory.

Preferred Share Purchase Rights

In 2002, our Board of Directors authorized and declared a dividend of one preferred share purchase right for each common share outstanding, and authorized and directed the issuance of one right per common share for any newly issued shares. The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group that attempts to acquire ConocoPhillips on terms not approved by the Board of Directors. However, since the rights may either be redeemed or otherwise made inapplicable by ConocoPhillips prior to an acquirer obtaining beneficial ownership of 15 percent or more of ConocoPhillips’ common stock, the rights should not interfere with any merger or business combination approved by the Board of Directors prior to that occurrence. The rights, which expire June 30, 2012, will be exercisable only if a person or group acquires 15 percent or more of the company’s common stock or commences a tender offer that would result in ownership of 15 percent or more of the common stock. Each right would entitle stockholders to buy one one-hundredth of a share of preferred stock at an exercise price of $300. If an acquirer obtains 15 percent or more of ConocoPhillips’ common stock, then each right will be adjusted so that it will entitle the holder (other than the acquirer, whose rights will become void) to purchase, for the then exercise price, a number of shares of ConocoPhillips’ common stock equal in value to two times the exercise price of the right. In addition, the rights enable holders to purchase the stock of an acquiring company at a discount, depending on specific circumstances. We may redeem the rights in whole, but not in part, for one cent per right.

Note 18—Non-Mineral Leases

The company leases ocean transport vessels, tugboats, barges, pipelines, railcars, corporate aircraft, service stations, drilling equipment, computers, office buildings and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements in regards to dividends, asset dispositions or borrowing ability. Leased assets under capital leases were not significant in any period presented.

At December 31, 2009, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2010	$ 872
2011	637
2012	529
2013	346
2014	272
Remaining years	721
Total	3,377
Less income from subleases	(142)*
Net minimum operating lease payments	$ 3,235

* *Includes $53 million related to railcars subleased to Chevron Phillips Chemical Company LLC, a related party.*

Operating lease rental expense for the years ended December 31 was:

	Millions of Dollars		
	2009	2008	2007
Total rentals*	$ **1,024**	1,033	855
Less sublease rentals	**(34)**	(125)	(82)
	$ **990**	908	773

* *Includes $21 million, $22 million and $27 million of contingent rentals in 2009, 2008 and 2007, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

Note 19—Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2009		2008			
	U.S.	**Int'l.**	U.S.	Int'l.	**2009**	2008
Change in Benefit Obligation						
Benefit obligation at January 1	$ **4,620**	**2,307**	4,281	3,085	**768**	792
Service cost	**194**	**79**	186	100	**9**	11
Interest cost	**277**	**144**	247	198	**47**	47
Plan participant contributions	**—**	**8**	—	10	**22**	32
Medicare Part D subsidy	**—**	**—**	—	—	**1**	8
Plan amendments	**—**	**—**	8	—	**—**	(47)
Actuarial (gain) loss	**456**	**366**	230	(180)	**63**	18
Acquisitions	**—**	**—**	—	—	**—**	—
Divestitures	**—**	**—**	—	—	**—**	—
Benefits paid	**(505)**	**(103)**	(332)	(117)	**(75)**	(85)
Curtailment	**—**	**—**	—	—	**—**	—
Recognition of termination benefits	**—**	**5**	—	2	**—**	—
Foreign currency exchange rate change	**—**	**295**	—	(791)	**4**	(8)
Benefit obligation at December 31*	$ **5,042**	**3,101**	4,620	2,307	**839**	768
* *Accumulated benefit obligation portion of above at December 31:*	*$* ***3,874***	***2,595***	*4,022*	*1,946*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	$ **2,373**	**1,728**	3,138	2,601	**2**	3
Acquisitions	**—**	**—**	—	—	**—**	—
Divestitures	**—**	**—**	—	—	**—**	—
Actual return on plan assets	**574**	**245**	(840)	(342)	**—**	(1)
Company contributions	**702**	**159**	407	170	**50**	45
Plan participant contributions	**—**	**8**	—	10	**22**	32
Medicare Part D subsidy	**—**	**—**	—	—	**1**	8
Benefits paid	**(505)**	**(103)**	(332)	(117)	**(75)**	(85)
Foreign currency exchange rate change	**—**	**244**	—	(594)	**—**	—
Fair value of plan assets at December 31:	$ **3,144**	**2,281**	2,373	1,728	**—**	2
Funded Status	$ **(1,898)**	**(820)**	(2,247)	(579)	**(839)**	(766)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2009		2008			
	U.S.	Int'l.	U.S.	Int'l.	2009	2008
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ —	**96**	—	33	**—**	—
Current liabilities	**(6)**	**(12)**	(6)	(9)	**(60)**	(49)
Noncurrent liabilities	**(1,892)**	**(904)**	(2,241)	(603)	**(779)**	(717)
Total recognized	$ **(1,898)**	**(820)**	(2,247)	(579)	**(839)**	(766)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**5.35%**	**5.80**	6.25	6.00	**5.60**	6.30
Rate of compensation increase	**4.00**	**4.50**	4.00	4.20	**—**	—
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**6.25%**	**6.00**	6.00	5.90	**6.30**	6.20
Expected return on plan assets	**7.00**	**6.60**	7.00	6.80	**7.00**	7.00
Rate of compensation increase	**4.00**	**4.20**	4.00	4.80	**—**	—

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

At December 31, 2007, all of our plans used a December 31 measurement date, except for a plan in the United Kingdom, which had a September 30 measurement date. To comply with the provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)," as codified into FASB ASC Topic 715, "Compensation—Retirement Benefits," we changed the measurement date for the U.K. plan from September 30 to December 31 for our 2008 consolidated financial statements. We elected to implement the change by remeasuring the U.K. plan assets and obligations as of December 31, 2007. To implement the change in measurement date, we recognized the $10 million (net of tax) of net periodic pension cost incurred from October 1, 2007, to December 31, 2007, as an adjustment to 2008 beginning retained earnings.

Included in other comprehensive income at December 31 were the following before-tax amounts that had not been recognized in net periodic postretirement benefit cost:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2009		2008			
	U.S.	Int'l.	U.S.	Int'l.	2009	2008
Unrecognized net actuarial loss (gain)	$ **1,664**	**574**	1,798	335	**(72)**	(149)
Unrecognized prior service cost	**58**	**(24)**	69	(22)	**(51)**	(43)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2009		2008			
	U.S.	**Int'l.**	U.S.	Int'l.	**2009**	2008
Sources of Change in Other Comprehensive Income						
Net gain (loss) arising during the period	**$ (52)**	**(274)**	(1,275)	(229)	**(62)**	(19)
Amortization of (gain) loss included in income	**186**	**35**	64	17	**(15)**	(17)
Net gain (loss) during the period	**$ 134**	**(239)**	(1,211)	(212)	**(77)**	(36)
Prior service cost arising during the period	**$ —**	**1**	(8)	(9)	**(1)**	47
Amortization of prior service cost included in income	**11**	**1**	10	1	**9**	11
Net prior service cost during the period	**$ 11**	**2**	2	(8)	**8**	58

Amounts included in accumulated other comprehensive income at December 31, 2009, that are expected to be amortized into net periodic postretirement cost during 2010 are provided below:

	Millions of Dollars		
	Pension Benefits		
	U.S.	Int'l.	Other Benefits
Unrecognized net actuarial loss (gain)	$ 167	57	(7)
Unrecognized prior service cost	10	1	3

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $7,145 million, $5,653 million, and $4,748 million, respectively, at December 31, 2009 and $6,092 million, $5,289 million, and $3,624 million, respectively, at December 31, 2008.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $419 million and $355 million, respectively, at December 31, 2009, and were $391 million and $334 million, respectively, at December 31, 2008.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2009		2008		2007				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2009**	2008	2007
Components of Net Periodic Benefit Cost									
Service cost	**$ 194**	**79**	186	85	175	98	**9**	11	14
Interest cost	**277**	**144**	247	170	229	161	**47**	47	45
Expected return on plan assets	**(184)**	**(125)**	(223)	(170)	(204)	(147)	**—**	—	—
Amortization of prior service cost	**11**	**1**	10	1	10	7	**9**	11	13
Recognized net actuarial loss (gain)	**186**	**35**	64	17	62	48	**(15)**	(17)	(20)
Net periodic benefit cost	**$ 484**	**134**	284	103	272	167	**50**	52	52

We recognized pension settlement losses of $15 million, $18 million and $2 million and special termination benefits of $5 million, $2 million and $1 million in 2009, 2008 and 2007, respectively. Curtailment losses of $1 million were recognized in 2007.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 8.25 percent in 2010 that declines to 5.0 percent by 2023. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2009 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 1	(1)
Effect on the postretirement benefit obligation	6	(6)

Plan Assets—We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate, and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 56 percent equity securities, 35 percent debt securities, 5 percent real estate, and 4 percent in all other types of investments. Generally, the investments in the plans are publicly traded, therefore minimizing liquidity risk in the portfolio.

Following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2009 and 2008.

Cash is valued at cost, which approximates fair value. Fair values of cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates.

Fair values of diversified equity securities, preferred stock and government debt securities categorized in Level 1 are primarily based on quoted market prices.

Fair values of diversified corporate debt securities, mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and market price quotations. If there have been no market transactions in a particular fixed income security, its fair market value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable price quotations are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades, issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.

Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.

Fair values of mutual funds are valued based on quoted market prices, which represent the net asset value of shares held.

Fair values of derivatives, which include options and swaps, are generally calculated from pricing models with market input parameters from third-party sources. Also included in this category are cash and short-term investments required to be held as collateral by brokers based on the fair value of certain derivative instruments. Some derivatives are publicly traded, and fair values for these are based on quoted market prices.

Private equity funds are valued at fair value using a variety of methods including consideration of the initial cost of securities or properties acquired, recent transactions in the same or comparable securities or properties, fundamental analytical techniques, real estate valuation techniques and other methods that reference third-party sources for discount and capitalization rates.

Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the Plans' participants.

Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.

A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract. This participating interest is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participation interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of comparison to quoted market prices and estimation using recently executed transactions and market price quotations for contract assets, and an actuarial present value computation for contract obligations. At December 31, 2009, the participating interest in the annuity contract was valued at $94 million and consisted of $349 million in debt securities, less $255 million for the accumulated benefit obligation covered by the contract. At December 31, 2008, the participating interest in the annuity contract was valued at $138 million and consisted of $400 million in debt securities, less $262 million for the accumulated benefit obligation covered by the contract. The net change from 2008 to 2009 is due to a decrease in the fair market value of the underlying investments of $51 million and a decrease in the present value of the contract obligation of $7 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

The fair values of our pension plan assets at December 31, 2009, by asset class are as follows:

	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 23	11	—	34
Diversified equity securities				
United States	1,077	—	—	1,077
International	808	—	—	808
Government debt securities				
United States	120	—	—	120
International	222	48	—	270
Diversified corporate debt securities				
United States	—	329	6	335
International	—	339	—	339
Mortgage-backed securities	—	107	—	107
Common/collective trusts	—	1,713	—	1,713
Mutual funds	432	—	—	432
Derivatives	—	12	—	12
Private equity funds	—	—	12	12
Insurance contracts	—	—	16	16
Preferred stock	3	—	—	3
Real estate	—	—	67	67
Total*	$ 2,685	2,559	101	5,345

* *Excludes the participating interest in the annuity contract with a net asset value of $94 million and net payables related to security transactions of $(14) million.*

The table below sets forth a summary of changes in the fair value of the Level 3 plan assets for the year ended December 31, 2009:

	Corporate Debt Securities	Private Equity Funds	Insurance Contracts	Real Estate	Total
Balance, beginning of year	$ 8	14	15	79	116
Return on plan assets	(1)	(3)	1	(9)	(12)
Purchases, sales and settlements	(1)	1	—	(3)	(3)
Balance, end of year	$ 6	12	16	67	101

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2010, we expect to contribute approximately $530 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $230 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the participating annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

	Millions of Dollars		
	Pension Benefits		
	U.S.	Int'l.	Other Benefits
2010	$ 378	95	51
2011	397	99	54
2012	488	104	57
2013	466	111	60
2014	510	116	63
2015-2019	2,872	693	350

Severance Accrual

As a result of the 2008 business environment's impact on our operating and capital plans, a reduction in our overall employee work force occurred in 2009. Various business units and staff groups recorded accruals in the fourth quarter of 2008 for severance and related employee benefits totaling $162 million. The following table summarizes our severance accrual activity at December 31:

	Millions of Dollars	
	2009	2008
Beginning balance	**$ 162**	—
Accruals	**5**	162
Benefit payments	**(75)**	—
Accrual reversals	**(80)**	—
Ending balance	**$ 12**	162

The remaining balance at December 31, 2009, of $12 million is classified as short term.

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 30 percent of their eligible pay up to the statutory limit ($16,500 in 2009) in the thrift feature of the CPSP to a choice of approximately 38 investment funds. ConocoPhillips matches contribution deposits, up to 1.25 percent of eligible pay. Company contributions charged to expense for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $23 million in 2009, $28 million in 2008, and $26 million in 2007.

The stock savings feature of the CPSP is a leveraged employee stock ownership plan. Employees may elect to participate in the stock savings feature by contributing 1 percent of eligible pay and receiving an allocation of shares of common stock proportionate to the amount of contribution.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (now the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guarantees the CPSP's borrowings, the unpaid balance is reported as a liability of the company and unearned compensation is shown as a reduction of common stockholders' equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP are released for allocation to participant accounts based on debt service payments on CPSP borrowings. In addition, during the period from 2010 through 2013, when no debt principal payments are scheduled to occur, we have committed to make direct contributions of stock to the stock savings feature of the CPSP, or make prepayments on CPSP borrowings, to ensure a certain minimum level of stock allocation to participant accounts.

We recognize interest expense as incurred and compensation expense based on the fair market value of the stock contributed or on the cost of the unallocated shares released, using the shares-allocated method. We recognized total CPSP expense related to the stock savings feature of $83 million, $111 million and $148 million in 2009, 2008 and 2007, respectively, all of which was compensation expense. In 2009, 2008 and 2007, we contributed 2,018,692 shares, 1,668,456 shares and 1,856,224 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $94 million, $120 million and $155 million, respectively. Dividends used to service debt were $39 million, $41 million and $39 million in 2009, 2008 and 2007, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2009, 2008 and 2007 was $2 million, $6 million and $11 million, respectively.

The total CPSP stock savings feature shares as of December 31 were:

	2009	2008
Unallocated shares	**5,364,887**	7,208,150
Allocated shares	**19,008,169**	18,000,395
Total shares	**24,373,056**	25,208,545

The fair value of unallocated shares at December 31, 2009 and 2008, was $274 million and $373 million, respectively.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $51 million in 2009, $53 million in 2008 and $44 million in 2007.

Share-Based Compensation Plans

The 2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2009. Over its 10-year life, the Plan allows the issuance of up to 70 million shares of our common stock for compensation to our employees, directors and consultants; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are canceled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 70 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares are available for awards in stock.

Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. For share-based awards granted prior to our adoption of SFAS No. 123(R), codified into FASB ASC Topic 718, “Compensation—Stock Compensation,” we recognize expense over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires. For share-based awards granted after our adoption of SFAS No. 123(R) on January 1, 2006, we recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture.

Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). For awards granted prior to our adoption of SFAS No. 123(R) that vest ratably, we recognize expense on a straight-line basis over the service period for each separate vesting portion of the award (i.e., as if the award was multiple awards with different requisite service periods). For share-based awards granted after our adoption of SFAS No. 123(R), we recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Total share-based compensation expense recognized in income and the associated tax benefit for the three years ended December 31, 2009, was as follows:

	Millions of Dollars		
	2009	2008	2007
Compensation cost	**$ 121**	193	242
Tax benefit	**42**	67	85

Stock Options—Stock options granted under the provisions of the Plan and earlier plans permit purchase of our common stock at exercise prices equivalent to the average market price of the stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The following summarizes our stock option activity for the three years ended December 31, 2009:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2006	54,048,779	$ 29.31		
Granted	2,530,648	66.37	$ 17.86	
Exercised	(12,176,988)	26.29		$ 926
Forfeited	(268,177)	65.02		
Expired or canceled	(29,407)	17.00		
Outstanding at December 31, 2007	44,104,855	$ 32.06		
Granted	2,211,202	79.35	$ 18.66	
Exercised	(9,493,818)	28.39		$ 535
Forfeited	(184,148)	73.91		
Expired or canceled	(22,338)	42.65		
Outstanding at December 31, 2008	36,615,753	$ 35.65		
Granted	**3,311,200**	**45.47**	**$ 11.18**	
Exercised	**(2,919,118)**	**24.10**		**$ 67**
Forfeited	**(332,941)**	**52.04**		
Expired or canceled	**(241,421)**	**63.49**		
Outstanding at December 31, 2009	**36,433,473**	**$ 37.13**		
Vested at December 31, 2009	**33,763,309**	**$ 35.52**		**$ 607**
Exercisable at December 31, 2009	**31,522,673**	**$ 34.08**		**$ 599**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2009, was 3.57 years and 3.21 years, respectively.

During 2009, we received $59 million in cash and realized a tax benefit of $20 million from the exercise of options. At December 31, 2009, the remaining unrecognized compensation expense from unvested options was $16 million, which will be recognized over a weighted-average period of 14 months, the longest period being 25 months.

The significant assumptions used to calculate the fair market values of the options granted over the past three years, as calculated using the Black-Scholes-Merton option-pricing model, were as follows:

	2009	2008	2007
Assumptions used			
Risk-free interest rate	**2.90%**	3.21	4.77
Dividend yield	**3.50%**	2.50	2.50
Volatility factor	**32.90%**	27.78	26.10
Expected life (years)	**6.53**	5.82	6.70

The ranges in the assumptions used were as follows:

	2009		2008		2007	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**2.90%**	**2.90**	3.45	2.27	4.90	4.77
Dividend yield	**3.50**	**3.50**	2.50	2.50	2.50	2.50
Volatility factor	**32.90**	**32.90**	32.10	26.70	26.10	26.10

We calculate volatility using the most recent ConocoPhillips end-of-week closing stock prices spanning a period equal to the expected life of the options granted. We periodically calculate the average period of time lapsed between grant dates and exercise dates of past grants to estimate the expected life of new option grants.

Stock Unit Program—Stock units granted under the provisions of the Plan vest ratably, with one-third of the units vesting in 36 months, one-third vesting in 48 months, and the final third vesting 60 months from the date of grant. Upon vesting, the units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to employees already eligible for retirement vest within six months of the grant date, but those units are not issued as shares until the end of the normal vesting period. Until issued as stock, most recipients of the units receive a quarterly cash payment of a dividend equivalent that is charged to expense. The grant date fair value of these units is deemed equal to the average ConocoPhillips stock price on the date of grant. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock unit activity for the three years ended December 31, 2009:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2006	5,087,138	$ 43.75	
Granted	1,721,521	65.27	
Forfeited	(162,992)	52.57	
Issued	(975,756)		$ 67
Outstanding at December 31, 2007	5,669,911	$ 51.28	
Granted	1,797,803	77.42	
Forfeited	(128,888)	62.82	
Issued	(1,411,128)		$ 109
Outstanding at December 31, 2008	5,927,698	$ 61.14	
Granted	**2,910,095**	**43.41**	
Forfeited	**(207,932)**	**51.84**	
Issued	**(1,910,309)**		**$ 88**
Outstanding at December 31, 2009	**6,719,552**	**$ 57.08**	
Not Vested at December 31, 2009	**5,532,043**	**$ 57.21**	

At December 31, 2009, the remaining unrecognized compensation cost from the unvested units was $162 million, which will be recognized over a weighted-average period of 24 months, the longest period being 49 months.

Performance Share Program—Under the Plan, we also annually grant to senior management restricted stock units that do not vest until either (i) with respect to awards for periods beginning before 2009, the employee becomes eligible for retirement by reaching age 55 with five years of service or (ii) with respect to awards for periods beginning in 2009, five years after the grant date of the award (although recipients can elect to defer the lapsing of restrictions until retirement after reaching age 55 with five years of service), so we recognize compensation expense for these awards beginning on the date of grant and ending on the date the units are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for such retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. These units are settled by issuing one share of ConocoPhillips common stock per unit. Until issued as stock, recipients of the units receive a quarterly cash payment of a dividend equivalent that is charged to expense. In its current form, the first grant of units under this program was in 2006.

The following summarizes our Performance Share Program activity for the three years ended December 31, 2009:

	Performance Share Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2006	1,456,241	$ 59.08	
Granted	1,349,475	66.37	
Forfeited	(22,062)	62.45	
Issued	(178,357)		$ 12
Outstanding at December 31, 2007	2,605,297	$ 62.49	
Granted	1,291,453	79.38	
Forfeited	(30,862)	69.24	
Issued	(689,710)		$ 58
Outstanding at December 31, 2008	3,176,178	$ 68.13	
Granted	**659,812**	**45.47**	
Forfeited	**(23,670)**	**65.00**	
Issued	**(407,442)**		**$ 19**
Outstanding at December 31, 2009	**3,404,878**	**$ 64.63**	
Not Vested at December 31, 2009	**1,298,896**	**$ 32.95**	

At December 31, 2009, the remaining unrecognized compensation cost from unvested Performance Share awards was $43 million, which will be recognized over a weighted-average period of 42 months, the longest period being 12 years.

Other—In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued to replace awards held by employees of companies we acquired or issued as part of a compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2009:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2006	3,602,375	$ 33.68	
Granted	293,024	67.30	
Issued	(227,766)		$ 17
Canceled	(180,489)	50.39	
Outstanding at December 31, 2007	3,487,144	$ 34.41	
Granted	237,642	78.59	
Issued	(128,803)		$ 9
Canceled	(231,963)	40.08	
Outstanding at December 31, 2008	3,364,020	$ 36.75	
Granted	**78,299**	**45.72**	
Issued	**(204,160)**		**$ 10**
Canceled	**(101,642)**	**52.91**	
Outstanding at December 31, 2009	**3,136,517**	**$ 35.11**	
Not Vested at December 31, 2009	**257,548**	**$ 73.01**	

At December 31, 2009, the remaining unrecognized compensation cost from the unvested units was $4 million, which will be recognized over a weighted-average period of 7 months, the longest period being 13 months.

Compensation and Benefits Trust

The Compensation and Benefits Trust (CBT) is an irrevocable grantor trust, administered by an independent trustee and designed to acquire, hold and distribute shares of our common stock to fund certain future compensation and benefit obligations of the company. The CBT does not increase or alter the amount of benefits or compensation that will be paid under existing plans, but offers us enhanced financial flexibility in providing the funding requirements of those plans. We also have flexibility in determining the timing of distributions of shares from the CBT to fund compensation and benefits, subject to a minimum distribution schedule. The trustee votes shares held by the CBT in accordance with voting directions from eligible employees, as specified in a trust agreement with the trustee.

We sold 58.4 million shares of previously unissued company common stock to the CBT in 1995 for $37 million of cash, previously contributed to the CBT by us, and a promissory note from the CBT to us of $952 million. The CBT is consolidated by ConocoPhillips; therefore, the cash contribution and promissory note are eliminated in consolidation. Shares held by the CBT are valued at cost and do not affect earnings per share or total common stockholders' equity until after they are transferred out of the CBT. In 2009 and 2008, shares transferred out of the CBT were 2,018,692 and 1,668,456, respectively. At December 31, 2009, the CBT had 38.5 million shares remaining. All shares are required to be transferred out of the CBT by January 1, 2021. The CBT, together with two smaller grantor trusts, comprise the "Grantor trusts" line in the equity section of the consolidated balance sheet.

Note 20—Income Taxes

Income taxes charged to income (loss) were:

	Millions of Dollars		
	2009	2008	2007
Income Taxes			
Federal			
Current	$ **575**	3,245	3,944
Deferred	**52**	(227)	312
Foreign			
Current	**5,584**	10,268	7,035
Deferred	**(1,239)**	(312)	(474)
State and local			
Current	**82**	543	602
Deferred	**42**	(112)	(38)
	$ **5,096**	13,405	11,381

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2009	2008
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$ 21,281**	20,563
Investment in joint ventures	**2,039**	1,778
Inventory	**13**	283
Partnership income deferral	**660**	1,172
Other	**813**	564
Total deferred tax liabilities	**24,806**	24,360
Deferred Tax Assets		
Benefit plan accruals	**1,802**	1,819
Asset retirement obligations and accrued environmental costs	**3,874**	3,232
Deferred state income tax	**251**	289
Other financial accruals and deferrals	**465**	712
Loss and credit carryforwards	**2,105**	1,657
Other	**484**	338
Total deferred tax assets	**8,981**	8,047
Less valuation allowance	**(1,540)**	(1,340)
Net deferred tax assets	**7,441**	6,707
Net deferred tax liabilities	**$ 17,365**	17,653

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $581 million, $21 million, $5 million and $17,962 million, respectively, at December 31, 2009, and $457 million, $58 million, $1 million and $18,167 million, respectively, at December 31, 2008.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2010 and 2029 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2009, valuation allowances increased a total of $200 million. This reflects increases of $224 million primarily related to U.S. foreign tax credit and foreign and state tax loss carryforwards and currency effects, partially offset by decreases of $24 million related to utilization of loss carryforwards and asset relinquishment. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

At December 31, 2009 and 2008, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,129 million and $3,871 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2009, 2008 and 2007.

	Millions of Dollars		
	2009	2008	2007
Balance at January 1	**$ 1,068**	1,143	912
Additions based on tax positions related to the current year	**18**	7	273
Additions for tax positions of prior years	**177**	186	145
Reductions for tax positions of prior years	**(33)**	(249)	(168)
Settlements	**(19)**	(16)	(15)
Lapse of statute	**(3)**	(3)	(4)
Balance at December 31	**$ 1,208**	1,068	1,143

Included in the balance of unrecognized tax benefits for 2009, 2008 and 2007 were $931 million, $862 million and $698 million, respectively, which, if recognized, would affect our effective tax rate. The increase from 2007 to 2008 was primarily due to the effect of FASB ASC Topic 805, "Business Combinations."

At December 31, 2009, 2008 and 2007, accrued liabilities for interest and penalties totaled $166 million, $147 million and $137 million, respectively, net of accrued income taxes. Interest and penalties affecting earnings in 2009, 2008 and 2007 were $14 million, $28 million and $46 million, respectively.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2007), Canada (2003), United States (2004) and Norway (2008). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pretax Income		
	2009	2008	2007	**2009**	2008	2007
Income (loss) before income taxes						
United States	**$ 2,456**	10,055	13,945	**24.5%**	(285.4)	59.7
Foreign	**7,576**	11,865	9,414	**75.5**	(336.8)	40.3
Goodwill impairment	**—**	(25,443)	—	**—**	722.2	—
	$ 10,032	(3,523)	23,359	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 3,511**	(1,233)	8,176	**35.0%**	35.0	35.0
Goodwill impairment	**—**	8,905	—	**—**	(252.8)	—
Foreign taxes in excess of federal statutory rate	**1,565**	5,670	3,225	**15.6**	(160.9)	13.8
Federal manufacturing deduction	**(19)**	(182)	(250)	**(0.2)**	5.2	(1.1)
State income tax	**81**	280	367	**0.8**	(8.0)	1.6
Other	**(42)**	(35)	(137)	**(0.4)**	1.0	(0.6)
	$ 5,096	13,405	11,381	**50.8%**	(380.5)	48.7

Our effective tax rate in 2009 was 51 percent, compared with a negative 381 percent in 2008. The change in the effective tax rate from 2008 was primarily due to the impact of impairments relating to goodwill and to our LUKOIL investment taken in the fourth quarter of 2008. For additional information on the impairments, see Note 9—Goodwill and Intangibles and Note 6—Investments, Loans and Long-Term Receivables.

Tax rate changes in 2009 and 2008 did not have a significant impact on our income tax expense. Our 2007 tax expense was decreased $204 million and $141 million, respectively, due to remeasurement of deferred tax liabilities resulting from tax rate reductions in Canada and Germany.

Note 21—Other Comprehensive Income (Loss)

The components and allocated tax effects of other comprehensive income (loss) follow:

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
2009			
Defined benefit pension plans:			
Prior service cost arising during the year	**$ —**	**—**	**—**
Reclassification adjustment for amortization of prior service cost included in net income	**21**	**14**	**7**
Net prior service cost	**21**	**14**	**7**
Net loss arising during the year	**(388)**	**(160)**	**(228)**
Reclassification adjustment for amortization of prior net losses included in net income	**206**	**77**	**129**
Net actuarial loss	**(182)**	**(83)**	**(99)**
Nonsponsored plans*	**39**	**17**	**22**
Foreign currency translation adjustments	**5,092**	**85**	**5,007**
Hedging activities	**(2)**	**(5)**	**3**
Other comprehensive income	**$ 4,968**	**28**	**4,940**
2008			
Defined benefit pension plans:			
Prior service cost arising during the year	$ 30	22	8
Reclassification adjustment for amortization of prior service cost included in net loss	22	8	14
Net prior service cost	52	30	22
Net loss arising during the year	(1,523)	(535)	(988)
Reclassification adjustment for amortization of prior net losses included in net loss	64	26	38
Net actuarial loss	(1,459)	(509)	(950)
Nonsponsored plans*	(41)	—	(41)
Foreign currency translation adjustments	(5,552)	(88)	(5,464)
Hedging activities	(4)	(2)	(2)
Other comprehensive loss	$ (7,004)	(569)	(6,435)
2007			
Defined benefit pension plans:			
Prior service cost arising during the year	$ 65	20	45
Reclassification adjustment for amortization of prior service cost included in net income	30	12	18
Net prior service cost	95	32	63
Net gain arising during the year	222	67	155
Reclassification adjustment for amortization of prior net losses included in net income	90	32	58
Net actuarial gain	312	99	213
Nonsponsored plans*	(2)	—	(2)
Foreign currency translation adjustments	3,214	139	3,075
Hedging activities	(3)	1	(4)
Other comprehensive income	$ 3,616	271	3,345

* *Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*

Deferred taxes have not been provided on temporary differences related to foreign currency translation adjustments for investments in certain foreign subsidiaries and foreign corporate joint ventures that are considered permanent in duration.

Accumulated other comprehensive income (loss) in the equity section of the balance sheet included:

	Millions of Dollars	
	2009	2008
Defined benefit pension liability adjustments	**$ (1,504)**	(1,434)
Foreign currency translation adjustments	**4,576**	(431)
Deferred net hedging loss	**(7)**	(10)
Accumulated other comprehensive income (loss)	**$ 3,065**	(1,875)

Note 22—Cash Flow Information

	Millions of Dollars		
	2009	2008	2007
Noncash Investing and Financing Activities			
Investment in an upstream business venture through issuance of an acquisition obligation	**$ —**	—	7,313
Investment in a downstream business venture through contribution of noncash assets and liabilities	**—**	—	2,428
Increase in PP&E related to an increase in asset retirement obligations	**974**	1,117	919
Cash Payments			
Interest	**$ 998**	858	1,040
Income taxes	**6,641**	13,122	11,330

Note 23—Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2009	2008	2007
Interest and Debt Expense			
Incurred			
Debt	$ **1,485**	1,189	1,369
Other	**291**	314	449
	1,776	1,503	1,818
Capitalized	**(487)**	(568)	(565)
Expensed	$ **1,289**	935	1,253
Other Income			
Interest income	$ **227**	245	342
Gain on asset dispositions	**160**	891	1,348
Business interruption insurance recoveries*	**—**	2	52
Other, net	**131**	(48)	229
	$ **518**	1,090	1,971

* *Primarily related to 2005 hurricanes in the Gulf of Mexico and southern United States.*

Research and Development Expenditures—expensed	$ **190**	209	160
Advertising Expenses	$ **60**	96	84
Shipping and Handling Costs*	$ **1,185**	1,443	1,493

* *Amounts included in production and operating expenses.*

Cash Dividends paid per common share	$ **1.91**	1.88	1.64
Foreign Currency Transaction Gains (Losses)—after-tax			
E&P	$ **(111)**	216	216
Midstream	**—**	1	(2)
R&M	**36**	(173)	(13)
LUKOIL Investment	**20**	(27)	5
Chemicals	**—**	—	—
Emerging Businesses	**2**	(7)	1
Corporate and Other	**97**	(72)	(120)
	$ **44**	(62)	87

Note 24—Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2009	2008	2007
Operating revenues and other income (a)	**$ 7,200**	13,097	10,949
Purchases (b)	**12,779**	19,409	15,722
Operating expenses and selling, general and administrative expenses (c)	**322**	515	416
Net interest expense (d)	**74**	66	99

(a) We sold natural gas to DCP Midstream, LLC and crude oil to the Malaysian Refining Company Sdn. Bhd. (MRC), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks were sold to Chevron Phillips Chemical Company LLC (CPChem), gas oil and hydrogen feedstocks were sold to Excel Paralubes and refined products were sold primarily to CFJ Properties and LUKOIL. Natural gas, crude oil, blendstock and other intermediate products were sold to WRB Refining LLC. In addition, we charged several of our affiliates, including CPChem, Merey Sweeny, L.P. (MSLP) and Hamaca Holding LLC (until expropriation on June 26, 2007), for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchased refined products from WRB. We purchased natural gas and natural gas liquids from DCP Midstream and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchased crude oil from LUKOIL, upgraded crude oil from Petrozuata C.A. (until expropriation on June 26, 2007) and refined products from MRC. We also paid fees to various pipeline equity companies for transporting finished refined products and natural gas, as well as a price upgrade to MSLP for heavy crude processing. We purchased base oils and fuel products from Excel Paralubes for use in our refinery and specialty businesses.

(c) We paid processing fees to various affiliates. Additionally, we paid crude oil transportation fees to pipeline equity companies.

(d) We paid and/or received interest to/from various affiliates, including FCCL Partnership. See Note 6—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

Note 25—Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in six operating segments:

1) E&P—This segment primarily explores for, produces, transports and markets crude oil, natural gas, natural gas liquids and bitumen on a worldwide basis. At December 31, 2009, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia. The E&P segment's U.S. and international operations are disclosed separately for reporting purposes.

2) Midstream—This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.

3) R&M—This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2009, we owned or had an interest in 12 refineries in the United States, one in the United Kingdom, one in Ireland, two in Germany, and one in Malaysia. The R&M segment's U.S. and international operations are disclosed separately for reporting purposes.

4) LUKOIL Investment—This segment represents our investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2009, our ownership interest was 20 percent based on issued shares and 20.09 percent based on estimated shares outstanding. See Note 6—Investments, Loans and Long-Term Receivables, for additional information.

5) Chemicals—This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC.

6) Emerging Businesses—This segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment.

Corporate and Other includes general corporate overhead, most interest expense and various other corporate activities. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1—Accounting Policies. Intersegment sales are at prices that approximate market.

Analysis of Results by Operating Segment

	Millions of Dollars		
	2009	2008	2007
Sales and Other Operating Revenues			
E&P			
United States	**$ 24,287**	51,378	36,974
International	**24,222**	36,972	24,617
Intersegment eliminations—U.S.	**(4,649)**	(8,034)	(6,096)
Intersegment eliminations—international	**(6,763)**	(10,498)	(7,341)
E&P	**37,097**	69,818	48,154
Midstream			
Total sales	**5,199**	6,791	5,106
Intersegment eliminations	**(307)**	(227)	(245)
Midstream	**4,892**	6,564	4,861
R&M			
United States	**73,871**	117,727	96,154
International	**34,025**	47,520	38,598
Intersegment eliminations—U.S.	**(613)**	(965)	(540)
Intersegment eliminations—international	**(50)**	(52)	(11)
R&M	**107,233**	164,230	134,201
LUKOIL Investment	**—**	—	—
Chemicals	**11**	11	10
Emerging Businesses			
Total sales	**593**	1,060	656
Intersegment eliminations	**(507)**	(861)	(458)
Emerging Businesses	**86**	199	198
Corporate and Other	**22**	20	13
Consolidated sales and other operating revenues	**$ 149,341**	240,842	187,437

Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 3,346**	3,725	3,328
International	**5,459**	5,096	9,121
Goodwill impairment	**—**	25,443	—
Total E&P	**8,805**	34,264	12,449
Midstream	**6**	6	14
R&M			
United States	**707**	1,129	609
International	**215**	425	139
Total R&M	**922**	1,554	748
LUKOIL Investment	**—**	7,410	—
Chemicals	**—**	—	—
Emerging Businesses	**21**	193	39
Corporate and Other	**76**	124	78
Consolidated depreciation, depletion, amortization and impairments	**$ 9,830**	43,551	13,328

	Millions of Dollars		
	2009	2008	2007
Equity in Earnings of Affiliates			
E&P			
United States	**$ (2)**	57	11
International	**233**	235	302
Total E&P	**231**	292	313
Midstream	**342**	810	599
R&M			
United States	**428**	836	1,710
International	**13**	178	240
Total R&M	**441**	1,014	1,950
LUKOIL Investment	**1,669**	2,011*	1,875
Chemicals	**298**	128	350
Emerging Businesses	**—**	(5)	—
Corporate and Other	**—**	—	—
Consolidated equity in earnings of affiliates	**$ 2,981**	4,250	5,087

* *Does not include a $7,410 million impairment of our LUKOIL investment presented as a separate line item in the consolidated statement of operations.*

Income Taxes			
E&P			
United States	**$ 786**	2,617	2,231
International	**4,325**	9,621	6,372
Total E&P	**5,111**	12,238	8,603
Midstream	**171**	261	237
R&M			
United States	**32**	934	2,571
International	**9**	214	113
Total R&M	**41**	1,148	2,684
LUKOIL Investment	**18**	49	45
Chemicals	**47**	15	(13)
Emerging Businesses	**(16)**	(6)	(33)
Corporate and Other	**(276)**	(300)	(142)
Consolidated income taxes	**$ 5,096**	13,405	11,381

Net Income (Loss) Attributable to ConocoPhillips			
E&P			
United States	**$ 1,503**	4,988	4,248
International	**2,101**	6,976	367
Goodwill impairment	**—**	(25,443)	—
Total E&P	**3,604**	(13,479)	4,615
Midstream	**313**	541	453
R&M			
United States	**(192)**	1,540	4,615
International	**229**	782	1,308
Total R&M	**37**	2,322	5,923
LUKOIL Investment	**1,663**	(5,488)	1,818
Chemicals	**248**	110	359
Emerging Businesses	**3**	30	(8)
Corporate and Other	**(1,010)**	(1,034)	(1,269)
Consolidated net income (loss) attributable to ConocoPhillips	**$ 4,858**	(16,998)	11,891

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	Millions of Dollars		
	2009	2008	2007
Investments In and Advances To Affiliates			
E&P			
United States	**$ 1,978**	1,368	1,059
International	**19,646**	16,772	12,055
Total E&P	**21,624**	18,140	13,114
Midstream	**1,199**	1,033	1,178
R&M			
United States	**3,982**	3,677	3,500
International	**1,142**	1,326	1,091
Total R&M	**5,124**	5,003	4,591
LUKOIL Investment	**6,861**	5,452	11,162
Chemicals	**2,446**	2,186	2,203
Emerging Businesses	**77**	75	79
Corporate and Other	**—**	—	—
Consolidated investments in and advances to affiliates*	**$ 37,331**	31,889	32,327
* *Includes amounts classified as held for sale:*	***$ 249***	*2*	*48*
Total Assets			
E&P			
United States	**$ 36,122**	36,962	35,160
International	**64,831**	58,912	59,412
Goodwill	**—**	—	25,569
Total E&P	**100,953**	95,874	120,141
Midstream	**2,054**	1,455	2,016
R&M			
United States	**24,963**	22,554	24,336
International	**8,446**	7,942	9,766
Goodwill	**3,638**	3,778	3,767
Total R&M	**37,047**	34,274	37,869
LUKOIL Investment	**6,866**	5,455	11,164
Chemicals	**2,451**	2,217	2,225
Emerging Businesses	**1,069**	924	1,230
Corporate and Other	**2,148**	2,666	3,112
Consolidated total assets	**$ 152,588**	142,865	177,757
Capital Expenditures and Investments			
E&P			
United States	**$ 3,474**	5,250	3,788
International	**5,425**	11,206	6,147
Total E&P	**8,899**	16,456	9,935
Midstream	**5**	4	5
R&M			
United States	**1,299**	1,643	1,146
International	**427**	626	240
Total R&M	**1,726**	2,269	1,386
LUKOIL Investment	**—**	—	—
Chemicals	**—**	—	—
Emerging Businesses	**97**	156	257
Corporate and Other	**134**	214	208
Consolidated capital expenditures and investments	**$ 10,861**	19,099	11,791

	Millions of Dollars		
	2009	2008	2007
Interest Income and Expense			
Interest income			
Corporate	**$ 89**	128	246
E&P	**91**	115	96
R&M	**47**	2	—
Interest and debt expense			
Corporate	**1,133**	762	1,066
E&P	**156**	173	187

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues*			Long-Lived Assets**		
	2009	2008	2007	**2009**	2008	2007
United States	**$ 97,674**	166,496	131,433	**53,761**	52,972	50,714
Australia***	**2,229**	2,735	1,633	**10,729**	8,656	3,420
Canada	**3,617**	5,226	4,727	**22,451**	20,429	24,758
Norway	**1,749**	3,036	2,479	**5,797**	5,002	6,180
Russia	**—**	—	—	**8,833**	7,604	13,359
United Kingdom	**20,671**	29,699	20,680	**5,778**	5,844	7,995
Other foreign countries	**23,401**	33,650	26,485	**17,441**	15,919	14,904
Worldwide consolidated	**$ 149,341**	240,842	187,437	**124,790**	116,426	121,330

* *Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*

** *Defined as net properties, plants and equipment plus investments in and advances to affiliated companies.*

*** *Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

Note 26—New Accounting Standards

In June 2009, the FASB issued SFAS No. 166, “Accounting for Transfers of Financial Assets, an amendment of FASB Statement No. 140.” This Statement was codified into FASB ASC Topic 860, “Transfers and Servicing.” This Statement removes the concept of a qualifying special purpose entity (SPE) and the exception for qualifying SPEs from the consolidation guidance. Additionally, the Statement clarifies the requirements for financial asset transfers eligible for sale accounting. This Statement is effective January 1, 2010, and is not expected to have a material impact on our consolidated financial statements.

Also in June 2009, the FASB issued SFAS No. 167, “Amendments to FASB Interpretation No. 46(R),” to address the effects of the elimination of the qualifying SPE concept in SFAS No. 166, and other concerns about the application of key provisions of consolidation guidance for VIEs. This Statement was codified into FASB ASC Topic 810, “Consolidation.” More specifically, SFAS No. 167 requires a qualitative rather than a quantitative approach to determine the primary beneficiary of a VIE, it amends certain guidance pertaining to the determination of the primary beneficiary when related parties are involved, and it amends certain guidance for determining whether an entity is a VIE. Additionally, this Statement requires continuous assessments of whether an enterprise is the primary beneficiary of a VIE. This Statement is effective January 1, 2010, and is not expected to have a material impact on our consolidated financial statements.

Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities, covering both those in our Exploration and Production (E&P) segment, as well as in our LUKOIL Investment segment. As a result, amounts reported as Equity Affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. The data included for the LUKOIL Investment segment reflects the company's estimated share of OAO LUKOIL's amounts. Because LUKOIL's accounting cycle close and preparation of U.S. generally accepted accounting principles financial statements occur subsequent to our reporting deadline, our equity share of financial information and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. Our estimated year-end 2009 reserves related to our equity investment in LUKOIL are based on LUKOIL's year-end 2009 reserve estimates and include adjustments to conform them to ConocoPhillips' reserves policy.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the "economic interest" method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2009, approximately 12 percent of our total proved reserves, excluding LUKOIL, were under PSCs, primarily in our Asia Pacific/Middle East geographic reporting area.

Our disclosures by geographic area include the United States, Canada, Europe (primarily Norway and the United Kingdom), Russia, Asia Pacific/Middle East, Africa, and Other Areas. Other Areas primarily consists of the Caspian Region, as well as the Petrozuata and Hamaca heavy oil projects in Venezuela, which were expropriated in 2007, and Ecuador, which was expropriated in 2009. Certain previously reported amounts for 2008 and 2007 appearing in the following oil and gas operations schedules have been reclassified between line items to conform to the current year presentation.

On December 31, 2008, the SEC issued its final rules to modernize the supplemental oil and gas disclosures, and in January 2010, the FASB issued Accounting Standards Update No. 2010-03, "Oil and Gas Reserve Estimation and Disclosures." As a result of these two new rules, our disclosures reflect the expanded definitions for oil and gas producing activities, including nontraditional resources such as our Syncrude operations. The inclusion of Syncrude as part of our oil and gas producing activities, effective January 1, 2009, did not have a significant impact on our disclosures. In the following disclosures, our synthetic oil classification includes our Syncrude mining operations, and our bitumen classification includes our Surmont operations and the FCCL Partnership. In addition, we have applied the 12-month average price rather than year-end price for determining economic producibility of reserves, revised our geographic areas, and expanded disclosures for equity investments to the same level of detail as required for consolidated investments.

We own a 9 percent interest in the Syncrude Canada Ltd. (SCL) joint venture, created for the purpose of mining shallow deposits of oil sands, extracting the bitumen, and upgrading it into a light sweet synthetic crude oil called Syncrude. The primary plant and facilities are located at Mildred Lake, about 25 miles north of Fort McMurray, Alberta. SCL, as operator of the joint venture, holds eight oil sands leases and the associated surface rights, of which our share is approximately 22,400 net acres. Net production averaged 23,000 barrels per day in 2009.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our E&P business units around the world. As part of our internal control process, each business unit's reserves are reviewed annually by an internal team which is headed by the company's Reserves Compliance and Reporting Manager. This team, composed of internal reservoir engineers, geologists and finance personnel, reviews the business units' reserves for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management and our internal audit group. The team is responsible for maintaining and communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

The technical person primarily responsible for overseeing the preparation of the company's reserve estimates is the Manager of Reserves Compliance and Reporting. This individual is a petroleum engineer with a bachelor's degree in petroleum engineering. He is an active member of the Society of Petroleum Engineers (SPE) with over 30 years of oil and gas industry experience, including drilling and production engineering assignments in several field locations. He is currently serving a three-year term on the Oil & Gas Reserves Committee of the SPE and has held positions of increasing responsibility in reservoir engineering, reserves reporting and compliance, and business management.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

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Proved Reserves

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Crude Oil and Natural Gas Liquids Millions of Barrels									
Developed and Undeveloped										
Consolidated operations										
End of 2006	1,495	745	2,240	134	705	—	372	316	149	3,916
Revisions	25	50	75	(3)	10	—	(25)	(13)	(2)	42
Improved recovery	25	16	41	—	—	—	—	—	—	41
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	26	27	53	5	9	—	76	16	—	159
Production	(103)	(63)	(166)	(17)	(80)	—	(39)	(28)	(4)	(334)
Sales	—	(1)	(1)	(18)	(1)	—	(9)	—	(17)	(46)
End of 2007	1,468	774	2,242	101	643	—	375	291	126	3,778
Revisions	(206)	(17)	(223)	4	(16)	—	15	15	9	(196)
Improved recovery	23	5	28	—	—	—	—	—	—	28
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	13	25	38	4	9	—	13	5	—	69
Production	(96)	(61)	(157)	(16)	(84)	—	(39)	(29)	(3)	(328)
Sales	—	—	—	—	—	—	—	—	(11)	(11)
End of 2008	1,202	726	1,928	93	552	—	364	282	121	3,340
Revisions	84	1	85	—	29	—	(12)	10	(8)	104
Improved recovery	13	2	15	—	—	—	2	—	—	17
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	14	17	31	3	7	—	26	3	—	70
Production	(93)	(60)	(153)	(15)	(87)	—	(48)	(28)	—	(331)
Sales	—	(1)	(1)	—	—	—	—	—	(5)	(6)
End of 2009	1,220	685	1,905	81	501	—	332	267	108	3,194
Equity affiliates										
End of 2006	—	—	—	—	—	1,607	92	—	1,023	2,722
Revisions	—	—	—	—	—	217	—	—	—	217
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	5	—	—	—	5
Extensions and discoveries	—	—	—	—	—	63	17	—	—	80
Production	—	—	—	—	—	(147)	—	—	(15)	(162)
Sales	—	—	—	—	—	(20)	—	—	(1,008)	(1,028)
End of 2007	—	—	—	—	—	1,725	109	—	—	1,834
Revisions	—	—	—	—	—	(36)	—	—	—	(36)
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	2	—	—	—	2
Extensions and discoveries	—	—	—	—	—	71	—	—	—	71
Production	—	—	—	—	—	(153)	—	—	—	(153)
Sales	—	—	—	—	—	(41)	—	—	—	(41)
End of 2008	—	—	—	—	—	1,568	109	—	—	1,677
Revisions	—	—	—	—	—	33	(3)	—	—	30
Improved recovery	—	—	—	—	—	54	—	—	—	54
Purchases	—	—	—	—	—	21	—	—	—	21
Extensions and discoveries	—	—	—	—	—	94	—	—	—	94
Production	—	—	—	—	—	(166)	—	—	—	(166)
Sales	—	—	—	—	—	—	—	—	—	—
End of 2009	—	—	—	—	—	1,604	106	—	—	1,710
Total company										
End of 2006	1,495	745	2,240	134	705	1,607	464	316	1,172	6,638
End of 2007	1,468	774	2,242	101	643	1,725	484	291	126	5,612
End of 2008	1,202	726	1,928	93	552	1,568	473	282	121	5,017
End of 2009	1,220	685	1,905	81	501	1,604	438	267	108	4,904

Years Ended December 31	Crude Oil and Natural Gas Liquids Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2006	1,393	627	2,020	114	387	—	239	292	13	3,065
End of 2007	1,371	624	1,995	87	370	—	200	260	9	2,921
End of 2008	1,104	572	1,676	85	342	—	217	264	6	2,590
End of 2009	1,130	558	1,688	77	312	—	221	246	—	2,544
Equity affiliates										
End of 2006	—	—	—	—	—	1,293	—	—	369	1,662
End of 2007	—	—	—	—	—	1,354	—	—	—	1,354
End of 2008	—	—	—	—	—	1,228	—	—	—	1,228
End of 2009	—	—	—	—	—	1,213	—	—	—	1,213
Undeveloped										
Consolidated operations										
End of 2006	102	118	220	20	318	—	133	24	136	851
End of 2007	97	150	247	14	273	—	175	31	117	857
End of 2008	98	154	252	8	210	—	147	18	115	750
End of 2009	90	127	217	4	189	—	111	21	108	650
Equity affiliates										
End of 2006	—	—	—	—	—	314	92	—	654	1,060
End of 2007	—	—	—	—	—	371	109	—	—	480
End of 2008	—	—	—	—	—	340	109	—	—	449
End of 2009	—	—	—	—	—	391	106	—	—	497

Notable changes in proved crude oil and natural gas liquids reserves in the three years ended December 31, 2009, included:

- *Revisions*: In 2009 and 2008, revisions in Alaska were primarily due to higher prices in 2009, versus 2008; and lower prices in 2008, compared with 2007, respectively. In 2007 for our equity affiliate operations, revisions were primarily attributable to LUKOIL.
- *Extensions and Discoveries*: In 2009 in Russia, extensions and discoveries were attributable to drilling success in various LUKOIL fields.
- *Sales*: In 2007 for our equity affiliates in Other Areas, sales were primarily due to the expropriation of our oil interests in Venezuela.

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Natural Gas Billions of Cubic Feet									
Developed and Undeveloped										
Consolidated operations										
End of 2006	3,414	9,027	12,441	3,310	2,852	—	3,570	1,086	187	23,446
Revisions	120	446	566	(41)	91	—	(47)	(26)	(12)	531
Improved recovery	5	1	6	—	—	—	—	—	—	6
Purchases	—	30	30	—	—	—	—	—	—	30
Extensions and discoveries	5	539	544	143	29	—	28	23	—	767
Production	(113)	(835)	(948)	(404)	(369)	—	(226)	(53)	(7)	(2,007)
Sales	—	(5)	(5)	(170)	(20)	—	(74)	—	(5)	(274)
End of 2007	3,431	9,203	12,634	2,838	2,583	—	3,251	1,030	163	22,499
Revisions	(852)	(270)	(1,122)	45	119	—	249	19	(1)	(691)
Improved recovery	15	2	17	—	—	—	—	—	—	17
Purchases	—	13	13	—	—	—	—	—	—	13
Extensions and discoveries	2	273	275	118	45	—	3	—	—	441
Production	(108)	(788)	(896)	(385)	(391)	—	(249)	(51)	(5)	(1,977)
Sales	—	(1)	(1)	(2)	(53)	—	(17)	—	(69)	(142)
End of 2008	2,488	8,432	10,920	2,614	2,303	—	3,237	998	88	20,160
Revisions	400	126	526	(23)	19	—	(94)	(2)	(32)	394
Improved recovery	3	—	3	—	—	—	—	—	—	3
Purchases	—	—	—	2	—	—	—	—	—	2
Extensions and discoveries	—	146	146	95	24	—	54	—	—	319
Production	(111)	(739)	(850)	(388)	(337)	—	(285)	(46)	—	(1,906)
Sales	—	(3)	(3)	(4)	—	—	—	—	—	(7)
End of 2009	2,780	7,962	10,742	2,296	2,009	—	2,912	950	56	18,965
Equity affiliates										
End of 2006	—	—	—	—	—	1,429	1,573	—	387	3,389
Revisions	—	—	—	—	—	(328)	1	—	—	(327)
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	—	—	—	—	13	351	—	—	364
Production	—	—	—	—	—	(100)	—	—	(3)	(103)
Sales	—	—	—	—	—	—	—	—	(384)	(384)
End of 2007	—	—	—	—	—	1,014	1,925	—	—	2,939
Revisions	—	—	—	—	—	1,394	—	—	—	1,394
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	598	—	—	598
Extensions and discoveries	—	—	—	—	—	37	—	—	—	37
Production	—	—	—	—	—	(114)	(4)	—	—	(118)
Sales	—	—	—	—	—	(62)	—	—	—	(62)
End of 2008	—	—	—	—	—	2,269	2,519	—	—	4,788
Revisions	—	—	—	—	—	436	(203)	—	—	233
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	25	—	—	—	25
Extensions and discoveries	—	—	—	—	—	89	294	—	—	383
Production	—	—	—	—	—	(114)	(33)	—	—	(147)
Sales	—	—	—	—	—	—	—	—	—	—
End of 2009	—	—	—	—	—	2,705	2,577	—	—	5,282
Total company										
End of 2006	3,414	9,027	12,441	3,310	2,852	1,429	5,143	1,086	574	26,835
End of 2007	3,431	9,203	12,634	2,838	2,583	1,014	5,176	1,030	163	25,438
End of 2008	2,488	8,432	10,920	2,614	2,303	2,269	5,756	998	88	24,948
End of 2009	2,780	7,962	10,742	2,296	2,009	2,705	5,489	950	56	24,247

Years Ended December 31	Natural Gas Billions of Cubic Feet Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2006	3,336	7,484	10,820	2,672	2,314	—	3,106	1,028	24	19,964
End of 2007	3,344	7,417	10,761	2,328	2,177	—	2,857	963	26	19,112
End of 2008	2,413	6,875	9,288	2,272	2,036	—	2,877	936	—	17,409
End of 2009	2,744	6,633	9,377	2,173	1,772	—	2,537	889	—	16,748
Equity affiliates										
End of 2006	—	—	—	—	—	655	—	—	173	828
End of 2007	—	—	—	—	—	698	—	—	—	698
End of 2008	—	—	—	—	—	1,458	361	—	—	1,819
End of 2009	—	—	—	—	—	1,506	307	—	—	1,813
Undeveloped										
Consolidated operations										
End of 2006	78	1,543	1,621	638	538	—	464	58	163	3,482
End of 2007	87	1,786	1,873	510	406	—	394	67	137	3,387
End of 2008	75	1,557	1,632	342	267	—	360	62	88	2,751
End of 2009	36	1,329	1,365	123	237	—	375	61	56	2,217
Equity affiliates										
End of 2006	—	—	—	—	—	774	1,573	—	214	2,561
End of 2007	—	—	—	—	—	316	1,925	—	—	2,241
End of 2008	—	—	—	—	—	811	2,158	—	—	2,969
End of 2009	—	—	—	—	—	1,199	2,270	—	—	3,469

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2009, included:

- *Revisions*: In 2009 and 2008, revisions in Alaska were primarily due to higher prices in 2009, versus 2008; and lower prices in 2008, compared with 2007, respectively. In 2009 for our equity affiliate operations in Asia Pacific/Middle East, revisions resulted from modified coalbed methane drilling plans in Australia. In Russia, revisions were attributable to positive performance in various LUKOIL fields. In 2008, revisions in Russia primarily resulted from a revised assessment of the reasonable certainty of project development and of the marketability of non-contracted gas volumes.
- *Purchases*: In 2008 for our equity affiliate operations in Asia Pacific/Middle East, purchases relate to our Australia Pacific LNG joint venture to develop coalbed methane.
- *Extensions and Discoveries*: In 2009 for our equity affiliate operations in Asia Pacific/Middle East, extensions and discoveries primarily resulted from drilling success in Australia related to a coalbed methane project.

Years Ended December 31	Other Products Millions of Barrels Synthetic Oil Canada	Bitumen Canada
Developed and Undeveloped		
Consolidated operations		
End of 2006	—	58
Revisions	—	27
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	—
Production	—	—
Sales	—	—
End of 2007	—	85
Revisions	—	17
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	—
Production	—	(2)
Sales	—	—
End of 2008	—	100
Revisions	256	152
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	167
Production	(8)	(2)
Sales	—	—
End of 2009	248	417
Equity affiliates		
End of 2006	—	—
Revisions	—	5
Improved recovery	—	—
Purchases	—	398
Extensions and discoveries	—	230
Production	—	(10)
Sales	—	—
End of 2007	—	623
Revisions	—	70
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	18
Production	—	(11)
Sales	—	—
End of 2008	—	700
Revisions	—	(87)
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	118
Production	—	(15)
Sales	—	—
End of 2009	—	716
Total company		
End of 2006	—	58
End of 2007	—	708
End of 2008	—	800
End of 2009	248	1,133

Years Ended December 31	Other Products Millions of Barrels	
	Synthetic Oil Canada	Bitumen Canada
Developed		
Consolidated operations		
End of 2006	—	—
End of 2007	—	17
End of 2008	—	24
End of 2009	248	24
Equity affiliates		
End of 2006	—	—
End of 2007	—	45
End of 2008	—	105
End of 2009	—	116
Undeveloped		
Consolidated operations		
End of 2006	—	58
End of 2007	—	68
End of 2008	—	76
End of 2009	—	393
Equity affiliates		
End of 2006	—	—
End of 2007	—	578
End of 2008	—	595
End of 2009	—	600

Notable changes in proved synthetic oil and bitumen reserves in the three years ended December 31, 2009, included:

- *Revisions*: In 2009 for synthetic oil consolidated operations, revisions reflect our Syncrude Canada Ltd. operations, which are now considered an oil and gas activity under the new FASB and SEC rules and regulations. For our bitumen consolidated operations, revisions primarily were related to the sanction of the Surmont Phase II Project. For our bitumen equity affiliate operations, revisions were mainly the result of the effect of higher prices on sliding scale royalty provisions.
- *Purchases*: In 2007 for our bitumen equity affiliate operations, purchases reflect the formation of FCCL.
- *Extensions and Discoveries*: In 2009 for our bitumen consolidated operations, extensions and discoveries were related to the sanction of the Surmont Phase II Project. For our equity affiliate operations, extensions and discoveries mainly reflect the approval of the FCCL Christina Lake Phase 1D Project. In 2007 for our bitumen equity affiliate operations, extensions and discoveries were primarily associated with FCCL.

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Total Proved Reserves Millions of Barrels of Oil Equivalent									
Developed and Undeveloped										
Consolidated operations										
End of 2006	2,064	2,250	4,314	744	1,180	—	967	497	180	7,882
Revisions	45	124	169	17	25	—	(33)	(17)	(4)	157
Improved recovery	26	16	42	—	—	—	—	—	—	42
Purchases	—	5	5	—	—	—	—	—	—	5
Extensions and discoveries	27	117	144	29	14	—	80	20	—	287
Production	(122)	(202)	(324)	(84)	(142)	—	(76)	(37)	(5)	(668)
Sales	—	(2)	(2)	(47)	(4)	—	(21)	—	(18)	(92)
End of 2007	2,040	2,308	4,348	659	1,073	—	917	463	153	7,613
Revisions	(348)	(62)	(410)	28	4	—	57	18	9	(294)
Improved recovery	26	5	31	—	—	—	—	—	—	31
Purchases	—	2	2	—	—	—	—	—	—	2
Extensions and discoveries	13	70	83	24	17	—	14	5	—	143
Production	(114)	(192)	(306)	(82)	(149)	—	(81)	(38)	(4)	(660)
Sales	—	—	—	—	(9)	—	(3)	—	(23)	(35)
End of 2008	1,617	2,131	3,748	629	936	—	904	448	135	6,800
Revisions	151	22	173	404	32	—	(28)	10	(13)	578
Improved recovery	14	2	16	—	—	—	2	—	—	18
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	14	41	55	186	11	—	35	3	—	290
Production	(112)	(183)	(295)	(89)	(143)	—	(96)	(36)	—	(659)
Sales	—	(1)	(1)	(1)	—	—	—	—	(5)	(7)
End of 2009	1,684	2,012	3,696	1,129	836	—	817	425	117	7,020
Equity affiliates										
End of 2006	—	—	—	—	—	1,845	354	—	1,088	3,287
Revisions	—	—	—	5	—	162	—	—	—	167
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	398	—	5	—	—	—	403
Extensions and discoveries	—	—	—	230	—	65	76	—	—	371
Production	—	—	—	(10)	—	(163)	—	—	(16)	(189)
Sales	—	—	—	—	—	(20)	—	—	(1,072)	(1,092)
End of 2007	—	—	—	623	—	1,894	430	—	—	2,947
Revisions	—	—	—	70	—	196	—	—	—	266
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	2	100	—	—	102
Extensions and discoveries	—	—	—	18	—	77	—	—	—	95
Production	—	—	—	(11)	—	(172)	(1)	—	—	(184)
Sales	—	—	—	—	—	(51)	—	—	—	(51)
End of 2008	—	—	—	700	—	1,946	529	—	—	3,175
Revisions	—	—	—	(87)	—	106	(37)	—	—	(18)
Improved recovery	—	—	—	—	—	54	—	—	—	54
Purchases	—	—	—	—	—	25	—	—	—	25
Extensions and discoveries	—	—	—	118	—	109	49	—	—	276
Production	—	—	—	(15)	—	(185)	(6)	—	—	(206)
Sales	—	—	—	—	—	—	—	—	—	—
End of 2009	—	—	—	716	—	2,055	535	—	—	3,306
Total company										
End of 2006	2,064	2,250	4,314	744	1,180	1,845	1,321	497	1,268	11,169
End of 2007	2,040	2,308	4,348	1,282	1,073	1,894	1,347	463	153	10,560
End of 2008	1,617	2,131	3,748	1,329	936	1,946	1,433	448	135	9,975
End of 2009	1,684	2,012	3,696	1,845	836	2,055	1,352	425	117	10,326

Years Ended December 31	Total Proved Reserves Millions of Barrels of Oil Equivalent Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2006	1,949	1,874	3,823	559	773	—	757	464	17	6,393
End of 2007	1,928	1,860	3,788	492	733	—	676	421	13	6,123
End of 2008	1,506	1,718	3,224	488	681	—	697	420	6	5,516
End of 2009	1,588	1,663	3,251	711	608	—	644	394	—	5,608
Equity affiliates										
End of 2006	—	—	—	—	—	1,402	—	—	398	1,800
End of 2007	—	—	—	45	—	1,470	—	—	—	1,515
End of 2008	—	—	—	105	—	1,471	60	—	—	1,636
End of 2009	—	—	—	116	—	1,464	51	—	—	1,631
Undeveloped										
Consolidated operations										
End of 2006	115	376	491	185	407	—	210	33	163	1,489
End of 2007	112	448	560	167	340	—	241	42	140	1,490
End of 2008	111	413	524	141	255	—	207	28	129	1,284
End of 2009	96	349	445	418	228	—	173	31	117	1,412
Equity affiliates										
End of 2006	—	—	—	—	—	443	354	—	690	1,487
End of 2007	—	—	—	578	—	424	430	—	—	1,432
End of 2008	—	—	—	595	—	475	469	—	—	1,539
End of 2009	—	—	—	600	—	591	484	—	—	1,675

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

Our total proved undeveloped reserves at December 31, 2009, were 3,087 million BOE.

The net addition of proved undeveloped reserves accounted for 52 percent, 156 percent and 77 percent of our total net additions in 2009, 2008 and 2007, respectively. During these years, we converted, on average, 13 percent per year of our proved undeveloped reserves to proved developed reserves. During 2009, we converted approximately 370 million BOE of proved undeveloped reserves to proved developed.

Costs incurred for the years ended December 31, 2009, 2008 and 2007, relating to the development of proved undeveloped reserves were $4.2 billion, $4.8 billion, and $4.3 billion, respectively.

Approximately 80 percent of our proved undeveloped reserves at year-end 2009 were associated with eight major development areas in our E&P segment; and our investment in LUKOIL. Six of the major development areas within E&P are currently producing and are expected to have proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

- FCCL oil sands—Christina Lake and Foster Creek in Canada.
- The Surmont oil sands project in Canada.
- The Ekofisk Field in the North Sea.
- Certain fields in the United States.

The remaining two major projects, Qatargas 3 in Qatar and the Kashagan Field in Kazakhstan, will have proved undeveloped reserves convert to developed as these projects begin production.

At the end of 2009, we did not have any material amounts of proved undeveloped reserves in individual fields or countries that have remained undeveloped for five years or more. However, our largest concentrations of proved undeveloped reserves at year-end 2009 are located in the Athabasca oil sands in Canada, consisting of the FCCL and Surmont steam-assisted gravity drainage (SAGD) projects. The majority of our proved undeveloped reserves in this area were first recorded in 2006 and 2007, and we expect a material portion of these reserves will remain undeveloped for more than five years.

Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated reserves are expected to be developed over many years as additional well pairs are drilled across the extensive resource base to maintain throughput at the central processing facilities.

Results of Operations

Year Ended December 31, 2009	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars									
Consolidated operations										
Sales	$3,935	3,144	7,079	2,179	4,995	—	3,830	1,562	11	19,656
Transfers	1,679	1,937	3,616	345	2,305	—	500	257	—	7,023
Other revenues	(83)	54	(29)	168	(66)	—	10	136	54	273
Total revenues	5,531	5,135	10,666	2,692	7,234	—	4,340	1,955	65	26,952
Production costs excluding taxes	864	1,266	2,130	1,011	1,048	—	445	270	8	4,912
Taxes other than income taxes	1,135	422	1,557	75	3	1	165	17	7	1,825
Exploration expenses	74	426	500	201	156	4	212	32	75	1,180
Depreciation, depletion and amortization	611	2,615	3,226	1,689	2,016	2	910	201	11	8,055
Impairments	—	5	5	296	104	—	12	—	51	468
Transportation costs	548	392	940	135	267	—	111	24	5	1,482
Other related expenses	138	60	198	(3)	62	3	121	23	14	418
Accretion	49	55	104	41	191	—	19	3	3	361
	2,112	(106)	2,006	(753)	3,387	(10)	2,345	1,385	(109)	8,251
Provision for income taxes	716	(79)	637	(309)	2,280	(3)	1,093	1,186	(21)	4,863
Results of operations for producing activities	1,396	(27)	1,369	(444)	1,107	(7)	1,252	199	(88)	3,388
Other earnings	144	(10)	134	(91)	(59)	(5)	132	4	(1)	114
Net income (loss) attributable to ConocoPhillips	$1,540	(37)	1,503	(535)	1,048	(12)	1,384	203	(89)	3,502
Equity affiliates										
Sales	$ —	—	—	713	—	5,514	74	—	—	6,301
Transfers	—	—	—	—	—	2,195	—	—	—	2,195
Other revenues	—	—	—	(2)	—	—	1	—	—	(1)
Total revenues	—	—	—	711	—	7,709	75	—	—	8,495
Production costs excluding taxes	—	—	—	213	—	635	26	—	—	874
Taxes other than income taxes	—	—	—	3	—	3,024	4	—	—	3,031
Exploration expenses	—	—	—	—	—	55	2	—	—	57
Depreciation, depletion and amortization	—	—	—	133	—	523	21	—	—	677
Impairments	—	—	—	—	—	277	—	—	—	277
Transportation costs	—	—	—	—	—	902	3	—	—	905
Other related expenses	—	—	—	17	—	3	1	—	—	21
Accretion	—	—	—	1	—	5	1	—	—	7
	—	—	—	344	—	2,285	17	—	—	2,646
Provision for income taxes	—	—	—	89	—	523	9	—	—	621
Results of operations for producing activities	—	—	—	255	—	1,762	8	—	—	2,025
Other earnings	—	—	—	—	—	(174)	(86)	—	—	(260)
Net income (loss) attributable to ConocoPhillips	$ —	—	—	255	—	1,588	(78)	—	—	1,765

Year Ended December 31, 2008	Millions of Dollars Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific / Middle East	Africa	Other Areas	Total
Consolidated operations										
Sales	$5,771	6,726	12,497	4,386	8,061	—	4,787	2,075	290	32,096
Transfers	3,444	3,401	6,845	—	3,415	—	579	669	—	11,508
Other revenues	(25)	98	73	317	477	—	40	230	(16)	1,121
Total revenues	9,190	10,225	19,415	4,703	11,953	—	5,406	2,974	274	44,725
Production costs excluding taxes	960	1,405	2,365	887	1,157	—	428	245	34	5,116
Taxes other than income taxes	3,432	764	4,196	61	29	2	295	27	205	4,815
Exploration expenses	99	469	568	240	235	4	148	41	103	1,339
Depreciation, depletion and amortization	559	2,426	2,985	1,802	1,917	2	733	215	24	7,678
Impairments*	—	620	620	92	72	—	9	—	—	793
Transportation costs	409	519	928	140	302	—	115	29	10	1,524
Other related expenses	(38)	108	70	56	(306)	18	113	6	53	10
Accretion	40	59	99	33	196	—	14	4	3	349
	3,729	3,855	7,584	1,392	8,351	(26)	3,551	2,407	(158)	23,101
Provision for income taxes	1,317	1,310	2,627	371	5,241	7	1,640	2,094	(46)	11,934
Results of operations for producing activities	2,412	2,545	4,957	1,021	3,110	(33)	1,911	313	(112)	11,167
Other earnings	(97)	128	31	243	314	66	46	(35)	(11)	654
Net income (loss) attributable to ConocoPhillips	$2,315	2,673	4,988	1,264	3,424	33	1,957	278	(123)	11,821
Equity affiliates										
Sales	$ —	—	—	644	—	5,451	9	—	—	6,104
Transfers	—	—	—	—	—	3,952	—	—	—	3,952
Other revenues	—	—	—	45	—	—	—	—	—	45
Total revenues	—	—	—	689	—	9,403	9	—	—	10,101
Production costs excluding taxes	—	—	—	182	—	766	4	—	—	952
Taxes other than income taxes	—	—	—	3	—	5,215	—	—	—	5,218
Exploration expenses	—	—	—	—	—	89	—	—	—	89
Depreciation, depletion and amortization	—	—	—	84	—	537	9	—	—	630
Impairments	—	—	—	—	—	6,666	—	—	—	6,666
Transportation costs	—	—	—	—	—	966	1	—	—	967
Other related expenses	—	—	—	1	—	7	5	—	—	13
Accretion	—	—	—	1	—	3	—	—	—	4
	—	—	—	418	—	(4,846)	(10)	—	—	(4,438)
Provision for income taxes	—	—	—	132	—	511	(11)	—	1	633
Results of operations for producing activities	—	—	—	286	—	(5,357)	1	—	(1)	(5,071)
Other earnings	—	—	—	3	—	(274)	(3)	—	—	(274)
Net income (loss) attributable to ConocoPhillips	$ —	—	—	289	—	(5,631)	(2)	—	(1)	(5,345)

* *Excludes goodwill impairment of $25,443 million.*

Year End December 31, 2007	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars									
Consolidated operations										
Sales	$4,659	5,422	10,081	3,406	5,701	—	3,484	1,515	240	24,427
Transfers	2,344	2,986	5,330	—	2,729	—	284	562	—	8,905
Other revenues	173	94	267	430	330	1	263	190	3	1,484
Total revenues	7,176	8,502	15,678	3,836	8,760	1	4,031	2,267	243	34,816
Production costs excluding taxes	775	1,232	2,007	874	1,029	—	423	224	41	4,598
Taxes other than income taxes	1,663	628	2,291	70	45	2	130	17	98	2,653
Exploration expenses	104	318	422	247	105	5	135	72	31	1,017
Depreciation, depletion and amortization	583	2,559	3,142	1,661	1,394	—	641	171	—	7,009
Impairments	28	43	71	27	188	—	26	—	918	1,230
Transportation costs	412	553	965	137	335	—	101	24	64	1,626
Other related expenses	(64)	72	8	(96)	46	16	14	8	77	73
Accretion	37	48	85	47	132	—	9	3	1	277
	3,638	3,049	6,687	869	5,486	(22)	2,552	1,748	(987)	16,333
Provision for income taxes	1,248	1,091	2,339	237	3,595	(6)	1,045	1,482	(21)	8,671
Results of operations for producing activities	2,390	1,958	4,348	632	1,891	(16)	1,507	266	(966)	7,662
Other earnings	(135)	35	(100)	280	48	36	94	(2)	194	550
Net income (loss) attributable to ConocoPhillips	$2,255	1,993	4,248	912	1,939	20	1,601	264	(772)	8,212
Equity affiliates										
Sales	$ —	—	—	365	—	4,400	—	—	447	5,212
Transfers	—	—	—	—	—	3,162	—	—	265	3,427
Other revenues	—	—	—	1	—	—	—	—	37	38
Total revenues	—	—	—	366	—	7,562	—	—	749	8,677
Production costs excluding taxes	—	—	—	131	—	677	—	—	98	906
Taxes other than income taxes	—	—	—	2	—	3,498	—	—	175	3,675
Exploration expenses	—	—	—	—	—	68	—	—	—	68
Depreciation, depletion and amortization	—	—	—	67	—	423	—	—	61	551
Impairments	—	—	—	—	—	—	—	—	3,825	3,825
Transportation costs	—	—	—	—	—	737	—	—	—	737
Other related expenses	—	—	—	27	—	14	5	—	11	57
Accretion	—	—	—	—	—	7	—	—	—	7
	—	—	—	139	—	2,138	(5)	—	(3,421)	(1,149)
Provision for income taxes	—	—	—	41	—	584	—	—	219	844
Results of operations for producing activities	—	—	—	98	—	1,554	(5)	—	(3,640)	(1,993)
Other earnings	—	—	—	2	—	258	(5)	—	(41)	214
Net income (loss) attributable to ConocoPhillips	$ —	—	—	100	—	1,812	(10)	—	(3,681)	(1,779)

- Results of operations for producing activities consist of all activities within the E&P organization and producing activities within the LUKOIL Investment segment, except for pipeline and marine operations, liquefied natural gas operations, and crude oil and gas marketing activities, which are included in other earnings. Also excluded are our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.
- Transfers are valued at prices that approximate market.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.
- Production costs are those incurred to operate and maintain wells and related equipment and facilities used to produce proved reserves. These costs also include depreciation of support equipment and administrative expenses related to the production activity.
- Taxes other than income taxes include production, property and other non-income taxes.
- Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, the costs of retaining undeveloped leaseholds, and depreciation of support equipment and administrative expenses related to the exploration activity.
- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 25—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, mainly due to depreciation of support equipment being reclassified to production or exploration expenses, as applicable, in Results of Operations. In addition, other earnings include certain E&P activities, including their related DD&A charges.
- Transportation costs include costs to transport our produced hydrocarbons to their points of sale, as well as processing fees paid to process natural gas to natural gas liquids. The profit element of transportation operations in which we have an ownership interest are deemed to be outside oil and gas producing activities. The net income of the transportation operations is included in other earnings.
- Other related expenses include foreign currency transaction gains and losses, and other miscellaneous expenses.
- The provision for income taxes is computed by adjusting each country's income before income taxes for permanent differences related to oil and gas producing activities that are reflected in our consolidated income tax expense for the period, multiplying the result by the country's statutory tax rate, and adjusting for applicable tax credits. Included in 2007 for Canada is a benefit related to the remeasurement of deferred tax liabilities from the 2007 Canadian graduated tax rate reduction.

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Statistics

	2009	2008	2007
	Thousands of Barrels Daily		
Net Production			
Crude Oil and Natural Gas Liquids			
Consolidated operations			
Alaska	**252**	261	280
Lower 48	**166**	165	181
United States	**418**	426	461
Canada	**40**	44	46
Europe	**241**	233	224
Asia Pacific/Middle East	**132**	107	106
Africa	**78**	80	78
Other areas	**4**	9	10
Total consolidated operations	**913**	899	925
Equity affiliates			
Russia	**442**	410	416
Other areas	**—**	—	42
Total equity affiliates	**442**	410	458
Total company	**1,355**	1,309	1,383
Synthetic Oil			
Consolidated operations—Canada	**23**	22	23
Bitumen			
Consolidated operations—Canada	**7**	6	—
Equity affiliates—Canada	**43**	30	27
Total company	**50**	36	27
	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**94**	97	110
Lower 48	**1,927**	1,994	2,182
United States	**2,021**	2,091	2,292
Canada	**1,062**	1,054	1,106
Europe	**876**	954	961
Asia Pacific/Middle East	**713**	609	579
Africa	**121**	114	125
Other areas	**—**	14	19
Total consolidated operations	**4,793**	4,836	5,082
Equity affiliates			
Russia	**280**	356	256
Asia Pacific/Middle East	**84**	11	—
Other areas	**—**	—	5
Total equity affiliates	**364**	367	261
Total company	**5,157**	5,203	5,343

* *Represents quantities available for sale. Excludes gas equivalent of natural gas liquids included above.*

	2009	2008	2007
Average Sales Prices			
Crude Oil and Natural Gas Liquids Per Barrel			
Consolidated operations			
Alaska	**$59.23**	99.10	69.79
Lower 48	**44.12**	74.70	55.15
United States	**53.21**	89.38	63.87
Canada	**41.76**	76.53	55.52
Europe	**58.92**	92.10	70.19
Asia Pacific/Middle East	**57.59**	87.32	67.20
Africa	**60.83**	91.54	71.84
Other areas	**32.01**	84.74	60.84
Total international	**57.40**	89.32	68.09
Total consolidated operations	**55.47**	89.35	66.01
Equity affiliates			
Russia	**47.02**	61.48	50.00
Other areas	—	—	47.46
Total equity affiliates	**47.02**	61.48	49.77
Synthetic Oil Per Barrel			
Consolidated operations—Canada	**$62.01**	103.31	74.32
Bitumen Per Barrel			
Consolidated operations—Canada	**$39.67**	46.85	—
Equity affiliates—Canada	**45.69**	58.54	37.94
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 6.25**	4.38	3.68
Lower 48	**3.42**	7.71	5.99
United States	**3.45**	7.67	5.98
Canada	**3.33**	7.92	6.09
Europe	**6.81**	10.55	7.87
Asia Pacific/Middle East	**5.84**	9.10	6.37
Africa	**1.56**	1.09	.80
Other areas	**—**	1.41	1.18
Total international	**4.94**	8.76	6.51
Total consolidated operations	**4.30**	8.28	6.26
Equity affiliates			
Russia	**1.18**	1.06	1.02
Asia Pacific/Middle East	**2.35**	2.04	—
Other areas	—	—	.30
Total equity affiliates	**1.45**	1.10	1.01

	2009	2008	2007
Average Production Costs Per Barrel of Oil Equivalent*			
Consolidated operations			
Alaska	$ **8.84**	9.46	7.12
Lower 48	**7.12**	7.72	6.20
United States	**7.73**	8.34	6.52
Canada	**11.21**	10.74	10.40
Europe	**7.42**	8.06	7.34
Asia Pacific/Middle East	**4.86**	5.61	5.72
Africa	**7.54**	6.76	6.21
Other areas	**5.48**	8.20	8.53
Total international	**7.72**	8.03	7.64
Total consolidated operations	**7.73**	8.17	7.11
Equity affiliates			
Canada	**13.57**	16.58	13.32
Russia	**3.56**	4.46	4.04
Asia Pacific/Middle East	**5.09**	5.96	—
Other areas	**—**	—	6.24
Total equity affiliates	**4.39**	5.19	4.70
Average Production Costs Per Barrel—Bitumen			
Consolidated operations—Canada	$ **30.92**	39.62	—
Equity affiliates—Canada	**13.57**	16.58	13.32
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent*			
Consolidated operations			
Alaska	$ **11.62**	33.83	15.27
Lower 48	**2.37**	4.20	3.16
United States	**5.65**	14.80	7.45
Canada	**.83**	.74	.83
Europe	**.02**	.20	.32
Asia Pacific/Middle East	**1.80**	3.87	1.76
Africa	**.47**	.75	.47
Other areas	**4.79**	49.42	20.39
Total international	**.74**	1.81	1.07
Total consolidated operations	**2.87**	7.69	4.10
Equity affiliates			
Canada	**.19**	.27	.21
Russia	**16.95**	30.36	20.89
Asia Pacific/Middle East	**.78**	—	—
Other areas	**—**	—	11.21
Total equity affiliates	**15.22**	28.45	19.05
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent*			
Consolidated operations			
Alaska	$ **6.25**	5.51	5.35
Lower 48	**14.71**	13.33	12.87
United States	**11.71**	10.53	10.21
Canada	**18.73**	21.82	19.76
Europe	**14.27**	13.36	9.94
Asia Pacific/Middle East	**9.94**	9.61	8.67
Africa	**5.61**	5.93	4.74
Other areas	**7.53**	5.79	—
Total international	**13.40**	13.69	11.40
Total consolidated operations	**12.67**	12.26	10.84
Equity affiliates			
Canada	**8.47**	7.65	6.82
Russia	**2.93**	3.13	2.53
Asia Pacific/Middle East	**4.11**	13.41	—
Other areas	**—**	—	3.88
Total equity affiliates	**3.40**	3.43	2.86

* *Includes bitumen. For 2008 and 2007, excludes our Canadian synthetic oil operations.*

	Productive			Dry		
	2009	2008	2007	**2009**	2008	2007
Net Wells Completed *(1)*						
Exploratory *(2)*						
Consolidated operations						
Alaska	**—**	—	3	**2**	1	1
Lower 48	**33**	81	71	**14**	22	9
United States	**33**	81	74	**16**	23	10
Canada	**17**	49	50	**19**	36	17
Europe	**1**	*	1	**2**	1	1
Asia Pacific/Middle East	**3**	1	4	**3**	*	1
Africa	*****	*	—	*****	1	1
Other areas	**—**	—	—	**—**	1	*
Total consolidated operations	**54**	131	129	**40**	62	30
Equity affiliates						
Russia	**1**	1	—	**—**	1	—
Asia Pacific/Middle East	**—**	—	—	**—**	*	—
Total equity affiliates *(3)*	**1**	1	—	**—**	1	—
Includes step-out wells of:	***40***	*127*	*99*	***29***	*27*	*18*

	Productive			Dry		
	2009	2008	2007	**2009**	2008	2007
Development						
Consolidated operations						
Alaska	**47**	47	46	**—**	—	—
Lower 48	**592**	690	686	**4**	8	7
United States	**639**	737	732	**4**	8	7
Canada	**227**	465	326	**20**	32	23
Europe	**9**	10	10	**—**	—	—
Asia Pacific/Middle East	**47**	26	18	**—**	—	—
Africa	**3**	4	6	**—**	—	*
Other areas	**—**	—	5	**—**	—	—
Total consolidated operations	**925**	1,242	1,097	**24**	40	30
Equity affiliates						
Canada	**61**	148	70	**—**	—	1
Russia	**6**	7	2	*****	—	—
Asia Pacific/Middle East	**28**	*	—	**—**	—	—
Total equity affiliates *(3)*	**95**	155	72	*****	—	1

(1) *Excludes farmout arrangements.*

(2) *Includes step-out wells, as well as other types of exploratory wells. Step-out exploratory wells are wells drilled in areas near or offsetting current production, for which we cannot demonstrate with certainty that there is continuity of production from an existing productive formation. These are classified as exploratory wells because we cannot attribute proved reserves to these locations.*

(3) *Excludes LUKOIL.*

* *Our total proportionate interest was less than one.*

Wells at Year-End 2009

	In Progress *(1)*		Productive *(2)*			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	22	11	1,935	868	29	19
Lower 48	96	73	12,958	4,758	26,053	16,631
United States	118	84	14,893	5,626	26,082	16,650
Canada	176*(3)*	134*(3)*	2,126	1,207	12,736	7,650
Europe	37	6	596	108	273	110
Asia Pacific/Middle East	140	62	439	174	93	44
Africa	35	7	1,117	192	—	—
Other areas	31	3	—	—	—	—
Total consolidated operations	537	296	19,171	7,307	39,184	24,454
Equity affiliates						
Canada	8	4	191	96	—	—
Russia	6	2	102	35	2	1
Asia Pacific/Middle East	574	143	—	—	498	153
Total equity affiliates *(4)*	588	149	293	131	500	154

(1) *Includes wells that have been temporarily suspended.*

(2) *Includes 6,098 gross and 3,845 net multiple completion wells.*

(3) *Includes 132 gross and 108 net stratigraphic test wells for heavy oil projects.*

(4) *Excludes LUKOIL.*

Acreage at December 31, 2009

	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	647	328	1,764	1,498
Lower 48	6,979	5,613	12,901	9,628
United States	7,626	5,941	14,665	11,126
Canada	7,258	4,528	10,650	6,726
Europe	848	228	3,535	1,444
Asia Pacific/Middle East	4,157	1,784	29,906	18,388
Africa	528	132	14,729	2,575
Other areas	—	—	13,313	9,062
Total consolidated operations	20,417	12,613	86,798	49,321
Equity affiliates				
Canada	32	14	505	203
Russia	291	90	1,173	476
Asia Pacific/Middle East	964	245	9,250	3,740
Total equity affiliates*	1,287	349	10,928	4,419

* *Excludes LUKOIL.*

Costs Incurred

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars									
2009										
Consolidated operations										
Unproved property acquisition	$ —	78	78	62	5	—	30	—	55	230
Proved property acquisition	1	6	7	7	—	—	—	—	—	14
	1	84	85	69	5	—	30	—	55	244
Exploration	137	476	613	251	184	4	342	33	90	1,517
Development	790	1,726	2,516	1,114	1,108	—	1,244	240	685	6,907
	$ 928	2,286	3,214	1,434	1,297	4	1,616	273	830	8,668
Equity affiliates										
Unproved property acquisition	$ —	—	—	—	—	5	—	—	—	5
Proved property acquisition	—	—	—	—	—	56	219	—	—	275
	—	—	—	—	—	61	219	—	—	280
Exploration	—	—	—	—	—	106	53	—	—	159
Development	—	—	—	446	—	1,007	376	—	—	1,829
	$ —	—	—	446	—	1,174	648	—	—	2,268
2008										
Consolidated operations										
Unproved property acquisition	$ 514	505	1,019	195	—	—	5	—	—	1,219
Proved property acquisition	—	37	37	—	—	—	—	—	—	37
	514	542	1,056	195	—	—	5	—	—	1,256
Exploration	124	733	857	306	279	3	224	42	94	1,805
Development	823	2,458	3,281	1,300	2,056	—	1,314	175	619	8,745
	$1,461	3,733	5,194	1,801	2,335	3	1,543	217	713	11,806
Equity affiliates										
Unproved property acquisition	$ —	—	—	—	—	39	4,505	—	—	4,544
Proved property acquisition	—	—	—	7	—	30	245	—	—	282
	—	—	—	7	—	69	4,750	—	—	4,826
Exploration	—	—	—	—	—	155	5	—	—	160
Development	—	—	—	569	—	1,842	214	—	—	2,625
	$ —	—	—	576	—	2,066	4,969	—	—	7,611

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars									
2007										
Consolidated operations										
Unproved property acquisition	$ 5	202	207	117	—	—	122	—	—	446
Proved property acquisition	—	42	42	—	—	—	—	—	—	42
	5	244	249	117	—	—	122	—	—	488
Exploration	115	468	583	278	235	5	153	67	53	1,374
Development	567	2,375	2,942	1,170	1,871	—	1,275	355	535	8,148
	$ 687	3,087	3,774	1,565	2,106	5	1,550	422	588	10,010
Equity affiliates										
Unproved property acquisition	$ —	—	—	2,030	—	105	—	—	—	2,135
Proved property acquisition	—	—	—	1,729	—	81	—	—	—	1,810
	—	—	—	3,759	—	186	—	—	—	3,945
Exploration	—	—	—	—	—	144	—	—	—	144
Development	—	—	—	358	—	1,763	334	—	51	2,506
	$ —	—	—	4,117	—	2,093	334	—	51	6,595

- Costs incurred include capitalized and expensed items.
- Acquisition costs include the costs of acquiring proved and unproved hydrocarbon properties. In 2008, equity affiliate acquisition costs were due to the Australia Pacific LNG joint venture with Origin Energy. In 2007, equity affiliate acquisition costs reflect the formation of FCCL.
- Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and exploratory drilling costs.
- Development costs include the cost of drilling and equipping development wells and building related production facilities for extracting, treating, gathering and storing hydrocarbons.

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Capitalized Costs

	Millions of Dollars									
At December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2009										
Consolidated operations										
Proved properties	$ 11,678	33,408	45,086	21,070	20,759	9	10,398	3,170	3,235	103,727
Unproved properties	1,421	1,407	2,828	1,899	396	—	970	195	218	6,506
	13,099	34,815	47,914	22,969	21,155	9	11,368	3,365	3,453	110,233
Accumulated depreciation, depletion and amortization	5,218	13,464	18,682	8,919	11,995	5	3,578	1,167	43	44,389
	$ 7,881	21,351	29,232	14,050	9,160	4	7,790	2,198	3,410	65,844
Equity affiliates										
Proved properties	$ —	—	—	3,912	—	12,562	1,511	—	—	17,985
Unproved properties	—	—	—	1,681	—	1,271	6,840	—	—	9,792
	—	—	—	5,593	—	13,833	8,351	—	—	27,777
Accumulated depreciation, depletion and amortization	—	—	—	299	—	8,901	36	—	—	9,236
	$ —	—	—	5,294	—	4,932	8,315	—	—	18,541
2008										
Consolidated operations										
Proved properties	$ 10,880	31,592	42,472	15,237	17,025	9	9,274	2,917	3,065	89,999
Unproved properties	1,388	1,541	2,929	1,672	316	—	833	261	181	6,192
	12,268	33,133	45,401	16,909	17,341	9	10,107	3,178	3,246	96,191
Accumulated depreciation, depletion and amortization	4,642	10,974	15,616	5,672	8,622	4	2,820	1,015	529	34,278
	$ 7,626	22,159	29,785	11,237	8,719	5	7,287	2,163	2,717	61,913
Equity affiliates										
Proved properties	$ —	—	—	2,787	—	11,498	1,076	—	—	15,361
Unproved properties	—	—	—	1,604	—	1,216	5,116	—	—	7,936
	—	—	—	4,391	—	12,714	6,192	—	—	23,297
Accumulated depreciation, depletion and amortization	—	—	—	133	—	8,129	9	—	—	8,271
	$ —	—	—	4,258	—	4,585	6,183	—	—	15,026

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P and LUKOIL Investment segments, excluding pipeline and marine operations, liquefied natural gas operations, crude oil and natural gas marketing activities, and downstream operations.
- Proved properties include capitalized costs for leaseholds holding proved reserves, development wells and related equipment and facilities (including uncompleted development well costs), mining facilities associated with our synthetic oil operations, and support equipment.
- Unproved properties include capitalized costs for leaseholds under exploration (including where hydrocarbons were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with new SEC and FASB requirements, amounts for 2009 were computed using 12-month average prices and end-of-year costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the month price for each month. Prior year amounts were computed using end-of-year prices and costs. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2009										
Consolidated operations										
Future cash inflows	$ 74,359	51,007	125,366	45,965	41,832	—	31,276	18,580	6,416	269,435
Less:										
Future production and transportation costs*	44,789	32,491	77,280	23,625	13,559	—	9,058	4,142	2,071	129,735
Future development costs	7,829	8,350	16,179	12,769	10,369	—	2,284	845	3,879	46,325
Future income tax provisions	7,519	2,992	10,511	2,183	10,676	—	7,288	10,223	71	40,952
Future net cash flows	14,222	7,174	21,396	7,388	7,228	—	12,646	3,370	395	52,423
10 percent annual discount	6,474	2,300	8,774	3,703	1,878	—	4,108	1,424	1,566	21,453
Discounted future net cash flows	$ 7,748	4,874	12,622	3,685	5,350	—	8,538	1,946	(1,171)	30,970
Equity affiliates										
Future cash inflows	$ —	—	—	36,540	—	69,277	19,420	—	—	125,237
Less:										
Future production and transportation costs*	—	—	—	13,689	—	49,874	13,891	—	—	77,454
Future development costs	—	—	—	4,481	—	7,795	350	—	—	12,626
Future income tax provisions	—	—	—	4,785	—	2,265	694	—	—	7,744
Future net cash flows	—	—	—	13,585	—	9,343	4,485	—	—	27,413
10 percent annual discount	—	—	—	9,512	—	4,002	2,018	—	—	15,532
Discounted future net cash flows	$ —	—	—	4,073	—	5,341	2,467	—	—	11,881
Total company										
Discounted future net cash flows	$ 7,748	4,874	12,622	7,758	5,350	5,341	11,005	1,946	(1,171)	42,851

* *Includes taxes other than income taxes.*

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2008										
Consolidated operations										
Future cash inflows	$ 54,662	51,354	106,016	19,632	42,230	—	22,626	11,388	4,357	206,249
Less:										
Future production and transportation costs*	35,150	30,508	65,658	9,357	12,217	—	6,960	3,567	2,000	99,759
Future development costs	9,681	10,443	20,124	4,188	8,835	—	2,859	440	2,084	38,530
Future income tax provisions	3,227	3,439	6,666	401	11,679	—	4,880	6,082	248	29,956
Future net cash flows	6,604	6,964	13,568	5,686	9,499	—	7,927	1,299	25	38,004
10 percent annual discount	2,159	2,886	5,045	1,222	3,178	—	2,998	398	703	13,544
Discounted future net cash flows	$ 4,445	4,078	8,523	4,464	6,321	—	4,929	901	(678)	24,460
Equity affiliates										
Future cash inflows	$ —	—	—	17,055	—	36,679	15,798	—	—	69,532
Less:										
Future production and transportation costs*	—	—	—	12,820	—	30,137	10,536	—	—	53,493
Future development costs	—	—	—	3,010	—	5,200	611	—	—	8,821
Future income tax provisions	—	—	—	252	—	260	379	—	—	891
Future net cash flows	—	—	—	973	—	1,082	4,272	—	—	6,327
10 percent annual discount	—	—	—	894	—	119	2,281	—	—	3,294
Discounted future net cash flows	$ —	—	—	79	—	963	1,991	—	—	3,033
Total company										
Discounted future net cash flows	$ 4,445	4,078	8,523	4,543	6,321	963	6,920	901	(678)	27,493

* *Includes taxes other than income taxes.*
Excludes discounted future net cash flows from Canadian Syncrude of $435 million.

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2007										
Consolidated operations										
Future cash inflows	$ 133,909	94,706	228,615	30,125	83,367	—	46,520	31,509	12,075	432,211
Less:										
Future production and transportation costs*	75,024	41,945	116,969	11,206	15,781	—	11,996	3,884	2,582	162,418
Future development costs	8,392	9,690	18,082	4,605	10,920	—	3,958	400	2,795	40,760
Future income tax provisions	18,798	14,793	33,591	2,235	37,645	—	12,331	22,599	1,690	110,091
Future net cash flows	31,695	28,278	59,973	12,079	19,021	—	18,235	4,626	5,008	118,942
10 percent annual discount	16,510	12,158	28,668	3,870	5,776	—	7,113	1,847	4,506	51,780
Discounted future net cash flows	$ 15,185	16,120	31,305	8,209	13,245	—	11,122	2,779	502	67,162
Equity affiliates										
Future cash inflows	$ —	—	—	30,626	—	116,893	22,156	—	—	169,675
Less:										
Future production and transportation costs*	—	—	—	11,495	—	80,571	11,429	—	—	103,495
Future development costs	—	—	—	3,065	—	7,518	264	—	—	10,847
Future income tax provisions	—	—	—	3,656	—	7,826	899	—	—	12,381
Future net cash flows	—	—	—	12,410	—	20,978	9,564	—	—	42,952
10 percent annual discount	—	—	—	8,521	—	9,293	5,111	—	—	22,925
Discounted future net cash flows	$ —	—	—	3,889	—	11,685	4,453	—	—	20,027
Total company										
Discounted future net cash flows	$ 15,185	16,120	31,305	12,098	13,245	11,685	15,575	2,779	502	87,189

* *Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $4,484 million.

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Discounted future net cash flows at the beginning of the year	**$ 24,460**	67,162	51,590	**3,033**	20,027	12,433	**27,493**	87,189	64,023
Changes during the year									
Revenues less production and transportation costs for the year*	**(18,460)**	(32,149)	(24,455)	**(3,686)**	(2,919)	(3,321)	**(22,146)**	(35,068)	(27,776)
Net change in prices, and production and transportation costs*	**19,318**	(73,477)	49,461	**15,279**	(22,495)	10,115	**34,597**	(95,972)	59,576
Extensions, discoveries and improved recovery, less estimated future costs	**2,303**	1,743	6,985	**1,342**	181	2,188	**3,645**	1,924	9,173
Development costs for the year	**6,148**	7,715	7,289	**1,623**	2,622	2,346	**7,771**	10,337	9,635
Changes in estimated future development costs	**(7,085)**	(3,129)	(10,813)	**(2,197)**	(813)	(3,468)	**(9,282)**	(3,942)	(14,281)
Purchases of reserves in place, less estimated future costs	**3**	10	51	**96**	321	2,989	**99**	331	3,040
Sales of reserves in place, less estimated future costs	**(75)**	(52)	(1,347)	**—**	(33)	(9,619)	**(75)**	(85)	(10,966)
Revisions of previous quantity estimates**	**5,140**	1,893	(79)	**(1,597)**	(1,689)	3,855	**3,543**	204	3,776
Accretion of discount	**3,924**	11,765	8,561	**365**	2,456	1,809	**4,289**	14,221	10,370
Net change in income taxes	**(4,706)**	42,979	(20,081)	**(2,377)**	5,375	700	**(7,083)**	48,354	(19,381)
Total changes	**6,510**	(42,702)	15,572	**8,848**	(16,994)	7,594	**15,358**	(59,696)	23,166
Discounted future net cash flows at year end	**$ 30,970**	24,460	67,162	**11,881**	3,033	20,027	**42,851**	27,493	87,189

* *Includes taxes other than income taxes.*

** *Includes amounts resulting from changes in the timing of production.*

- The net change in prices, and production and transportation costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.
- For 2009, as required, purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent. For prior years the end-of-year sales prices were used, as required.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production, transportation and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions.

Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars			Per Share of Common Stock Net Income (Loss) Attributable to ConocoPhillips	
	Sales and Other Operating Revenues*	Income (Loss) Before Income Taxes	Net Income (Loss) Attributable to ConocoPhillips	Basic	Diluted
2009					
First	**$ 30,741**	**2,034**	**840**	**.57**	**.56**
Second	**35,448**	**2,382**	**1,298**	**.87**	**.87**
Third	**40,173**	**2,947**	**1,503**	**1.00**	**1.00**
Fourth	**42,979**	**2,669**	**1,217**	**.82**	**.81**
2008					
First	$ 54,883	7,568	4,139	2.65	2.62
Second	71,411	9,812	5,439	3.54	3.50
Third	70,044	9,482	5,188	3.43	3.39
Fourth**	44,504	(30,385)	(31,764)	(21.37)	(21.37)

* *Includes excise taxes on petroleum products sales.*

** *Includes noncash impairments relating to goodwill and to our LUKOIL investment that together amount to $32,853 million before- and after-tax.*

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to publicly held debt securities. ConocoPhillips Company is wholly owned by ConocoPhillips. ConocoPhillips Australia Funding Company is an indirect, wholly owned subsidiary of ConocoPhillips Company. ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II are indirect, wholly owned subsidiaries of ConocoPhillips. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

In February 2009, we filed a universal shelf registration statement with the SEC under which ConocoPhillips, as a well-known seasoned issuer, has the ability to issue and sell an indeterminate amount of various types of debt and equity securities, with certain debt securities guaranteed by ConocoPhillips Company. Also as part of that registration statement, ConocoPhillips Trust I and ConocoPhillips Trust II have the ability to issue and sell preferred trust securities, guaranteed by ConocoPhillips. ConocoPhillips Trust I and ConocoPhillips Trust II have not issued any trust-preferred securities under this registration statement, and thus have no assets or liabilities. Accordingly, columns for these two trusts are not included in the condensed consolidating financial information.

To facilitate the restructuring of certain legal entities within the Canada operating unit, ConocoPhillips Canada Funding Company I (CFC I) entered into a transaction with another wholly owned subsidiary of ConocoPhillips (included in the "All Other Subsidiaries" column) whereby it acquired an investment in certain preferred shares of a Canadian legal entity within the ConocoPhillips group, in exchange for a non-interest-bearing demand note payable. The value ascribed to the preferred shares and note payable represented the redemption price for both. This noncash transaction was effective December 31, 2009. As a result, the balance sheet of CFC I reflects a short-term investment of $2,973 million and a corresponding amount in short-term debt. In January 2010, the preferred shares acquired under the above transaction were resold to the original holder at the same value as the original purchase price, as satisfaction of the obligation under the demand note payable. A pro forma presentation of CFC I's December 31, 2009, balance sheet reflecting this subsequent event would show balances of $-0- in short-term investments and short-term debt. As these transactions were completed between wholly owned subsidiaries of ConocoPhillips, there is no impact on the consolidated results in either period.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

	Millions of Dollars							
	Year Ended December 31, 2009							
Statement of Operations	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income								
Sales and other operating revenues	$ —	90,916	—	—	—	58,425	—	149,341
Equity in earnings of affiliates	5,259	5,903	—	—	—	2,116	(10,297)	2,981
Other income (loss)	—	553	—	—	—	(35)	—	518
Intercompany revenues	30	1,119	51	78	48	18,478	(19,804)	—
Total Revenues and Other Income	5,289	98,491	51	78	48	78,984	(30,101)	152,840
Costs and Expenses								
Purchased crude oil, natural gas and products	—	80,280	—	—	—	41,122	(18,969)	102,433
Production and operating expenses	2	4,421	—	—	—	6,013	(97)	10,339
Selling, general and administrative expenses	15	1,194	—	—	—	639	(18)	1,830
Exploration expenses	—	295	—	—	—	887	—	1,182
Depreciation, depletion and amortization	—	1,710	—	—	—	7,585	—	9,295
Impairments	—	63	—	—	—	472	—	535
Taxes other than income taxes	—	4,875	—	—	—	10,674	(20)	15,529
Accretion on discounted liabilities	—	59	—	—	—	363	—	422
Interest and debt expense	631	155	46	77	53	1,027	(700)	1,289
Foreign currency transaction (gains) losses	—	(35)	—	171	216	(398)	—	(46)
Total Costs and Expenses	648	93,017	46	248	269	68,384	(19,804)	142,808
Income (loss) before income taxes	4,641	5,474	5	(170)	(221)	10,600	(10,297)	10,032
Provision for income taxes	(217)	215	2	4	(24)	5,116	—	5,096
Net income (loss)	4,858	5,259	3	(174)	(197)	5,484	(10,297)	4,936
Less: net income attributable to noncontrolling interests	—	—	—	—	—	(78)	—	(78)
Net Income (Loss) Attributable to ConocoPhillips	$ 4,858	5,259	3	(174)	(197)	5,406	(10,297)	4,858

Statement of Operations	Year Ended December 31, 2008							
Revenues and Other Income								
Sales and other operating revenues	$ —	153,695	—	—	—	87,147	—	240,842
Equity in earnings of affiliates	(16,789)	(12,073)	—	—	—	4,242	28,870	4,250
Other income (loss)	(3)	797	—	—	—	296	—	1,090
Intercompany revenues	26	3,390	86	85	52	30,348	(33,987)	—
Total Revenues and Other Income	(16,766)	145,809	86	85	52	122,033	(5,117)	246,182
Costs and Expenses								
Purchased crude oil, natural gas and products	—	139,857	—	—	—	61,165	(32,359)	168,663
Production and operating expenses	—	5,028	—	—	—	6,910	(120)	11,818
Selling, general and administrative expenses	12	1,365	—	—	—	909	(57)	2,229
Exploration expenses	—	278	—	—	—	1,059	—	1,337
Depreciation, depletion and amortization	—	1,525	—	—	—	7,487	—	9,012
Impairments	—	9,863	—	—	—	24,676	—	34,539
Taxes other than income taxes	—	5,040	—	—	—	15,831	(234)	20,637
Accretion on discounted liabilities	—	59	—	—	—	359	—	418

Interest and debt expense	334	603	79	77	53	1,006	(1,217)	935
Foreign currency transaction (gains) losses	—	50	—	(254)	(295)	616	—	117
Total Costs and Expenses	346	163,668	79	(177)	(242)	120,018	(33,987)	249,705
Income (loss) before income taxes	(17,112)	(17,859)	7	262	294	2,015	28,870	(3,523)
Provision for income taxes	(114)	1,301	3	(10)	20	12,205	—	13,405
Net income (loss)	(16,998)	(19,160)	4	272	274	(10,190)	28,870	(16,928)
Less: net income attributable to noncontrolling interests	—	—	—	—	—	(70)	—	(70)
Net Income (Loss) Attributable to ConocoPhillips	$ (16,998)	(19,160)	4	272	274	(10,260)	28,870	(16,998)

Statement of Operations	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars							
	Year Ended December 31, 2007							
Revenues and Other Income								
Sales and other operating revenues	$ —	120,687	—	—	—	66,750	—	187,437
Equity in earnings of affiliates	12,071	9,800	—	—	—	3,025	(19,809)	5,087
Other income	4	505	—	—	—	1,462	—	1,971
Intercompany revenues	149	3,014	117	83	51	18,407	(21,821)	—
Total Revenues and Other Income	12,224	134,006	117	83	51	89,644	(41,630)	194,495
Costs and Expenses								
Purchased crude oil, natural gas and products	—	103,516	—	—	—	38,880	(18,967)	123,429
Production and operating expenses	—	4,522	—	—	—	6,247	(86)	10,683
Selling, general and administrative expenses	17	1,407	—	—	—	943	(61)	2,306
Exploration expenses	—	111	—	—	—	896	—	1,007
Depreciation, depletion and amortization	—	1,476	—	—	—	6,822	—	8,298
Impairments	—	1,852	—	—	—	3,178	—	5,030
Taxes other than income taxes	—	5,463	—	—	—	13,802	(275)	18,990
Accretion on discounted liabilities	—	55	—	—	—	286	—	341
Interest and debt expense	423	1,758	109	77	53	1,265	(2,432)	1,253
Foreign currency transaction (gains) losses	—	12	—	166	124	(503)	—	(201)
Total Costs and Expenses	440	120,172	109	243	177	71,816	(21,821)	171,136
Income (loss) before income taxes	11,784	13,834	8	(160)	(126)	17,828	(19,809)	23,359
Provision for income taxes	(107)	2,810	3	16	6	8,653	—	11,381
Net income (loss)	11,891	11,024	5	(176)	(132)	9,175	(19,809)	11,978
Less: net income attributable to noncontrolling interests	—	—	—	—	—	(87)	—	(87)
Net Income (Loss) Attributable to ConocoPhillips	$ 11,891	11,024	5	(176)	(132)	9,088	(19,809)	11,891

Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars							
	At December 31, 2009							
Assets								
Cash and cash equivalents	$ —	122	—	18	1	554	(153)	542
Accounts and notes receivable	26	6,495	—	—	—	13,712	(7,018)	13,215
Inventories	—	2,911	—	—	—	2,029	—	4,940
Short-term investments	—	—	—	2,973	—	—	(2,973)	—
Prepaid expenses and other current assets	13	835	—	4	3	1,621	(6)	2,470
Total Current Assets	39	10,363	—	2,995	4	17,916	(10,150)	21,167
Investments, loans and long-term receivables*	71,213	92,087	759	1,376	933	48,336	(176,160)	38,544
Net properties, plants and equipment	—	19,838	—	—	—	67,870	—	87,708
Goodwill	—	3,638	—	—	—	—	—	3,638
Intangibles	—	770	—	—	—	53	—	823
Other assets	55	240	1	3	4	509	(104)	708
Total Assets	$ 71,307	126,936	760	4,374	941	134,684	(186,414)	152,588
Liabilities and Stockholders' Equity								
Accounts payable	$ 7	11,590	—	1	1	10,904	(7,018)	15,485
Short-term debt	235	1,286	—	2,973	—	207	(2,973)	1,728
Accrued income and other taxes	—	298	—	(1)	—	3,105	—	3,402
Employee benefit obligations	—	588	—	—	—	258	—	846
Other accruals	262	643	9	15	10	1,301	(6)	2,234
Total Current Liabilities	504	14,405	9	2,988	11	15,775	(9,997)	23,695
Long-term debt	12,561	4,053	749	1,250	849	7,463	—	26,925
Asset retirement obligations and accrued environmental costs	—	1,406	—	—	—	7,307	—	8,713
Joint venture acquisition obligation	—	—	—	—	—	5,009	—	5,009
Deferred income taxes	(4)	2,785	—	10	10	15,161	—	17,962
Employee benefit obligations	—	2,960	—	—	—	1,170	—	4,130
Other liabilities and deferred credits*	2,560	25,819	—	68	37	17,296	(42,683)	3,097
Total Liabilities	15,621	51,428	758	4,316	907	69,181	(52,680)	89,531
Retained earnings	26,158	10,051	—	(49)	(30)	10,684	(14,156)	32,658
Other common stockholders' equity	29,528	65,457	2	107	64	54,229	(119,578)	29,809
Noncontrolling interests	—	—	—	—	—	590	—	590
Total Liabilities and Stockholders' Equity	$ 71,307	126,936	760	4,374	941	134,684	(186,414)	152,588

* *Includes intercompany loans.*

Balance Sheet	At December 31, 2008							
Assets								
Cash and cash equivalents	$ —	8	—	10	1	750	(14)	755
Accounts and notes receivable	13	10,541	15	—	—	21,314	(19,888)	11,995
Inventories	—	2,909	—	—	—	2,287	(101)	5,095
Prepaid expenses and other current assets	10	1,170	—	14	10	1,794	—	2,998
Total Current Assets	23	14,628	15	24	11	26,145	(20,003)	20,843
Investments, loans and long-term receivables*	61,144	83,645	1,699	1,183	802	44,629	(160,203)	32,899
Net properties, plants and equipment	—	19,017	—	—	—	64,928	2	83,947
Goodwill	—	3,778	—	—	—	—	—	3,778
Intangibles	—	784	—	—	—	62	—	846
Other assets	13	243	2	109	183	286	(284)	552
Total Assets	$ 61,180	122,095	1,716	1,316	996	136,050	(180,488)	142,865

Liabilities and Stockholders' Equity								
Accounts payable	$ —	17,566	—	2	1	16,309	(19,888)	13,990
Short-term debt	—	301	950	—	—	68	(949)	370
Accrued income and other taxes	—	233	—	(1)	(1)	4,042	—	4,273
Employee benefit obligations	—	702	—	—	—	237	—	939
Other accruals	25	883	18	15	10	1,280	(23)	2,208
Total Current Liabilities	25	19,685	968	16	10	21,936	(20,860)	21,780
Long-term debt	7,703	5,364	749	1,250	848	10,221	950	27,085
Asset retirement obligations and accrued environmental costs	—	1,101	—	—	—	6,062	—	7,163
Joint venture acquisition obligation	—	—	—	—	—	5,669	—	5,669
Deferred income taxes	(4)	2,882	—	9	34	15,258	(12)	18,167
Employee benefit obligations	—	3,367	—	—	—	760	—	4,127
Other liabilities and deferred credits*	4,954	24,609	—	—	—	16,976	(43,930)	2,609
Total Liabilities	12,678	57,008	1,717	1,275	892	76,882	(63,852)	86,600
Retained earnings	24,130	4,792	(3)	125	167	7,234	(5,803)	30,642
Other common stockholders' equity	24,372	60,295	2	(84)	(63)	50,834	(110,833)	24,523
Noncontrolling interests	—	—	—	—	—	1,100	—	1,100
Total	$ 61,180	122,095	1,716	1,316	996	136,050	(180,488)	142,865

* *Includes intercompany loans.*

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Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars							
	Year Ended December 31, 2009							
Cash Flows From Operating Activities								
Net Cash Provided by (Used in) Operating Activities	$ (2,205)	6,451	—	8	—	10,309	(2,084)	12,479
Cash Flows From Investing Activities								
Capital expenditures and investments	—	(3,157)	—	—	—	(8,384)	680	(10,861)
Proceeds from asset dispositions	—	629	—	—	—	960	(319)	1,270
Long-term advances/loans—related parties	—	(425)	—	—	—	(681)	581	(525)
Collection of advances/loans—related parties	—	168	950	—	—	3,808	(4,833)	93
Other	—	46	—	—	—	42	—	88
Net Cash Provided by (Used in) Investing Activities	—	(2,739)	950	—	—	(4,255)	(3,891)	(9,935)
Cash Flows From Financing Activities								
Issuance of debt	8,909	490	—	—	—	269	(581)	9,087
Repayment of debt	(3,826)	(4,106)	(950)	—	—	(3,809)	4,833	(7,858)
Issuance of company common stock	13	—	—	—	—	—	—	13
Dividends paid on common stock	(2,832)	—	—	—	—	(1,945)	1,945	(2,832)
Other	(59)	18	—	—	—	(863)	(361)	(1,265)
Net Cash Provided by (Used in) Financing Activities	2,205	(3,598)	(950)	—	—	(6,348)	5,836	(2,855)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	—	—	—	98	—	98
Net Change in Cash and Cash Equivalents	—	114	—	8	—	(196)	(139)	(213)
Cash and cash equivalents at beginning of year	—	8	—	10	1	750	(14)	755
Cash and Cash Equivalents at End of Year	$ —	122	—	18	1	554	(153)	542

Statement of Cash Flows	Year Ended December 31, 2008							
Cash Flows From Operating Activities								
Net Cash Provided by (Used in) Operating Activities	$ 12,641	2,077	6	3	—	10,815	(2,884)	22,658
Cash Flows From Investing Activities								
Capital expenditures and investments	—	(5,131)	—	—	—	(14,848)	880	(19,099)
Proceeds from asset dispositions	—	271	—	—	—	1,549	(180)	1,640
Long-term advances/loans—related parties	(5,000)	(5,815)	—	—	—	(3,396)	14,048	(163)
Collection of advances/loans—related parties	—	293	—	—	—	17	(276)	34
Other	—	(8)	—	—	—	(20)	—	(28)
Net Cash Provided by (Used in) Investing Activities	(5,000)	(10,390)	—	—	—	(16,698)	14,472	(17,616)

Cash Flows From Financing Activities								
Issuance of debt	4,779	8,266	—	—	—	8,660	(14,048)	7,657
Repayment of debt	(1,500)	(361)	—	—	—	(312)	276	(1,897)
Issuance of company common stock	198	—	—	—	—	—	—	198
Repurchase of company common stock	(8,249)	—	—	—	—	—	—	(8,249)
Dividends paid on common stock	(2,854)	—	(6)	—	—	(3,237)	3,243	(2,854)
Other	(15)	134	—	—	—	(38)	(700)	(619)
Net Cash Provided by (Used in) Financing Activities	(7,641)	8,039	(6)	—	—	5,073	(11,229)	(5,764)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	87	—	—	—	(66)	—	21
Net Change in Cash and Cash Equivalents	—	(187)	—	3	—	(876)	359	(701)
Cash and cash equivalents at beginning of year	—	195	—	7	1	1,626	(373)	1,456
Cash and Cash Equivalents at End of Year	$ —	8	—	10	1	750	(14)	755

	Millions of Dollars							
	Year Ended December 31, 2007							
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities								
Net Cash Provided by (Used in) Operating Activities	$ 14,984	9,944	10	7	—	26,021	(26,416)	24,550
Cash Flows From Investing Activities								
Capital expenditures and investments	—	(2,967)	—	—	—	(9,121)	297	(11,791)
Proceeds from asset dispositions	—	1,391	—	—	—	3,029	(848)	3,572
Long-term advances/loans—related parties	—	(491)	—	—	—	(2,649)	2,458	(682)
Collection of advances/loans—related parties	—	1,238	300	—	—	837	(2,286)	89
Other	1	83	—	—	—	166	—	250
Net Cash Provided by (Used in) Investing Activities	1	(746)	300	—	—	(7,738)	(379)	(8,562)
Cash Flows From Financing Activities								
Issuance of debt	(39)	2,179	—	—	—	1,253	(2,458)	935
Repayment of debt	(5,564)	(1,385)	(300)	—	—	(1,491)	2,286	(6,454)
Issuance of company common stock	285	—	—	—	—	—	—	285
Repurchase of company common stock	(7,001)	—	—	—	—	—	—	(7,001)
Dividends paid on common stock	(2,661)	(10,000)	(10)	—	—	(16,376)	26,386	(2,661)
Other	(5)	87	—	—	—	(1,076)	550	(444)
Net Cash Provided by (Used in) Financing Activities	(14,985)	(9,119)	(310)	—	—	(17,690)	26,764	(15,340)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	—	—	—	(9)	—	(9)
Net Change in Cash and Cash Equivalents	—	79	—	7	—	584	(31)	639
Cash and cash equivalents at beginning of year	—	116	—	—	1	1,042	(342)	817
Cash and Cash Equivalents at End of Year	$ —	195	—	7	1	1,626	(373)	1,456

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2009, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Senior Vice President, Finance, and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the Act), of the effectiveness of the design and operation of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Senior Vice President, Finance, and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of December 31, 2009.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the quarterly period ended December 31, 2009, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 71 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

This report is included in Item 8 on page 73 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 28 and 29.

Code of Business Ethics and Conduct for Directors and Employees

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the "Corporate Governance" section of our Internet Web site at *www.conocophillips.com* (within the Investor Relations>Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our Internet Web site.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2010 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2010, and is incorporated herein by reference.*

Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2010 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2010, and is incorporated herein by reference.*

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2010 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2010, and is incorporated herein by reference.*

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2010 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2010, and is incorporated herein by reference.*

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2010 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2010, and is incorporated herein by reference.*

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* *Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2010 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 70, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II—Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 174 through 177 are filed as part of this annual report.

(c) Financial statements of OAO LUKOIL will be filed by amendment to this Annual Report on Form 10-K no later than June 30, 2010, in accordance with Rule 3.09 of Regulation S-X.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

	Millions of Dollars				
Description	Balance at January 1	Charged to Expense	Other (a)	Deductions	Balance at December 31
2009					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 61**	**69**	**2**	**(56)(b)**	**76**
Deferred tax asset valuation allowance	**1,340**	**200**	**2**	**(2)**	**1,540**
Included in other liabilities:					
Restructuring accruals	**196**	**41**	**(76)**	**(88)(c)**	**73**
2008					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 58	38	(4)	(31)(b)	61
Deferred tax asset valuation allowance	1,269	220	1	(150)	1,340
Included in other liabilities:					
Restructuring accruals	117	125	11	(57)(c)	196
2007					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 45	23	(2)	(8)(b)	58
Deferred tax asset valuation allowance	822	67	417	(37)	1,269
Included in other liabilities:					
Restructuring accruals	164	31	5	(83)(c)	117

(a) Represents acquisitions/dispositions/revisions and the effect of translating foreign financial statements.

(b) Amounts charged off less recoveries of amounts previously charged off.

(c) Benefit payments.

CONOCOPHILLIPS

INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
3.3	By-Laws of ConocoPhillips, as amended on December 12, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 12, 2008; File No. 001-32395).
4.1	Rights agreement, dated as of June 30, 2002, between ConocoPhillips and Mellon Investor Services LLC, as rights agent, which includes as Exhibit A the form of Certificate of Designations of Series A Junior Participating Preferred Stock, as Exhibit B the form of Rights Certificate and as Exhibit C the Summary of Rights to Purchase Preferred Stock (incorporated by reference to Exhibit 4.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	Shareholder Agreement, dated September 29, 2004, by and between LUKOIL and ConocoPhillips (incorporated by reference to Exhibit 99.2 of the Current Report of ConocoPhillips on Form 8-K filed on September 30, 2004; File No. 333-74798).
10.2	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.3	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.5	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).

Exhibit Number	Description
10.6	ConocoPhillips Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.7	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.9	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.10	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.11	ConocoPhillips Key Employee Supplemental Retirement Plan (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.12.1	Defined Contribution Make-Up Plan of ConocoPhillips—Title I (incorporated by reference to Exhibit 10.13.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.12.2	Defined Contribution Make-Up Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.12.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.13	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.14	1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.15	1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.16	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).

Exhibit Number	Description
10.17	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.18	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521).
10.18.1	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.19	ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.19.1	First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
10.20	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.21.1	Key Employee Deferred Compensation Plan of ConocoPhillips—Title I (incorporated by reference to Exhibit 10.23.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.21.2	Key Employee Deferred Compensation Plan of ConocoPhillips—Title II (incorporated by reference to Exhibit 10.21.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.22	ConocoPhillips Key Employee Change in Control Severance Plan (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.23	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.24	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987).
10.25	Aircraft Time Sharing Agreement by and between James J. Mulva and ConocoPhillips (incorporated by reference to Exhibit 10 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2007; File No. 001-32395).
10.26	Form of Stock Option Award Agreement under the ConocoPhillips Stock Option and Stock Appreciation Rights Program (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).

Exhibit Number	Description
10.27	Form of Restricted Stock Unit Award Agreement under the ConocoPhillips Performance Share Program (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.28	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395).
10.29	Letter Agreement between ConocoPhillips and John E. Lowe, dated October 1, 2008 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 1, 2008; File No. 001-32395).
10.30	Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.31	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395).
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries of ConocoPhillips.
23	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.
101. INS	XBRL Instance Document.
101. SCH	XBRL Schema Document.
101. CAL	XBRL Calculation Linkbase Document.
101. DEF	XBRL Definition Linkbase Document.
101. LAB	XBRL Labels Linkbase Document.
101. PRE	XBRL Presentation Linkbase Document.

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SIGNATURES

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

CONOCOPHILLIPS

February 25, 2010	/s/ James J. Mulva *James J. Mulva* Chairman of the Board of Directors and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 25, 2010, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ James J. Mulva *James J. Mulva*	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ Sigmund L. Cornelius *Sigmund L. Cornelius*	Senior Vice President, Finance, and Chief Financial Officer (Principal financial officer)
/s/ Glenda M. Schwarz *Glenda M. Schwarz*	Vice President and Controller (Principal accounting officer)

/s/ Richard L. Armitage *Richard L. Armitage*	Director
/s/ Richard H. Auchinleck *Richard H. Auchinleck*	Director
/s/ James E. Copeland, Jr. *James E. Copeland, Jr.*	Director
/s/ Kenneth M. Duberstein *Kenneth M. Duberstein*	Director
/s/ Ruth R. Harkin *Ruth R. Harkin*	Director
/s/ Harold W. McGraw, III *Harold W. McGraw, III*	Director
/s/ Robert A. Niblock *Robert A. Niblock*	Director
/s/ Harald J. Norvik *Harald J. Norvik*	Director
/s/ William K. Reilly *William K. Reilly*	Director
/s/ Bobby S. Shackouls *Bobby S. Shackouls*	Director
/s/ Victoria J. Tschinkel *Victoria J. Tschinkel*	Director
/s/ Kathryn C. Turner *Kathryn C. Turner*	Director
/s/ William E. Wade, Jr. *William E. Wade, Jr.*	Director

Exhibit 12

CONOCOPHILLIPS AND CONSOLIDATED SUBSIDIARIES
TOTAL ENTERPRISE
Computation of Ratio of Earnings to Fixed Charges

	Millions of Dollars				
	Years Ended December 31				
	2009	2008	2007	2006	2005
Earnings Available for Fixed Charges					
Income from continuing operations before income taxes and minority interest	$ 9,957	(3,565)	23,310	28,371	23,547
Distributions less than equity in earnings of fifty-percent-or-less-owned companies	(1,704)	5,790	(1,839)	(962)	(1,785)
Fixed charges, excluding capitalized interest*	1,700	1,288	1,680	1,410	747
	$ 9,953	3,513	23,151	28,819	22,509
Fixed Charges					
Interest and expense on indebtedness, excluding capitalized interest	$ 1,289	935	1,253	1,087	497
Capitalized interest	487	568	565	458	395
Preferred dividend requirements of subsidiary and capital trusts	—	—	—	—	—
Interest portion of rental expense	205	207	171	232	188
Interest expense relating to guaranteed debt of fifty-percent-or-less-owned companies	—	3	19	—	—
Interest expense relating to guaranteed debt of greater than fifty-percent-owned companies	—	—	—	—	—
	$ 1,981	1,713	2,008	1,777	1,080
Ratio of Earnings to Fixed Charges	5.0	2.1	11.5	16.2	20.8

* *Includes amortization of capitalized interest totaling approximately $206 million in 2009, $143 million in 2008, $237 million in 2007, $92 million in 2006 and $62 million in 2005.*

SUBSIDIARY LISTING OF CONOCOPHILLIPS

Listed below are subsidiaries of the registrant at December 31, 2009. Certain subsidiaries are omitted since such companies considered in the aggregate do not constitute a significant subsidiary.

Company Name	Incorporation Location
Ashford Energy Capital S.A.	Luxembourg
BR (Global) Holdings B.V.	Netherlands
BROG LP Inc.	Delaware
Burlington Resources (Irish Sea) Limited	England
Burlington Resources (Netherlands) B.V.	Netherlands
Burlington Resources (UK) Holdings Limited	England
Burlington Resources Algeria Holdings Ltd.	Bermuda
Burlington Resources Canada (Hunter) Ltd.	Alberta
Burlington Resources China Holdings Limited	Bermuda
Burlington Resources China LLC	Delaware
Burlington Resources Finance Company	Nova Scotia
Burlington Resources Inc.	Delaware
Burlington Resources International Holdings LLC	Delaware
Burlington Resources International Inc.	Delaware
Burlington Resources Offshore Inc.	Delaware
Burlington Resources Oil & Gas Company LP	Delaware
Burlington Resources Trading Inc.	Delaware
Canadian Hunter Resources	Alberta
Clearwater Ltd.	Bermuda
Conoco AG, Zug	Switzerland
Conoco Central Europe Inc.	Delaware
Conoco Funding Company	Nova Scotia
Conoco Orinoco Inc.	Delaware
Conoco Petroleum Operations LLC	Delaware
Conoco Venezuela C.A.	Venezuela
ConocoPhillips (03-12) Pty Ltd	Victoria
ConocoPhillips (Grissik) Ltd.	Bermuda
ConocoPhillips (Timor Sea) Pty Ltd	Western Australia
ConocoPhillips (UK) Cuu Long Ltd.	England
ConocoPhillips (U.K.) Eta Limited	England
ConocoPhillips (U.K.) Gama Limited	England
ConocoPhillips (U.K.) Limited	England
ConocoPhillips (U.K.) Theta Limited	England
ConocoPhillips (U.K.) Zeta Limited	England
ConocoPhillips Alaska, Inc.	Delaware
ConocoPhillips Alaska Natural Gas Corp.	Delaware
ConocoPhillips Algeria Ltd.	Cayman Islands
ConocoPhillips Australia Funding Company	Delaware
ConocoPhillips Australia Gas Holdings Pty Ltd.	Western Australia

Exhibit 21

Company Name	Incorporation Location
ConocoPhillips Australia Holdings Pty Ltd	Australia
ConocoPhillips Australia Pacific LNG PTY Ltd	Western Australia
ConocoPhillips Australia Pty Ltd	Western Australia
ConocoPhillips Bohai Limited	Bahamas
ConocoPhillips Canada (BRC) Ltd.	Alberta
ConocoPhillips Canada (BRC) Partnership	Alberta
ConocoPhillips Canada Energy Partnership	Alberta
ConocoPhillips Canada Funding Company I	Nova Scotia
ConocoPhillips Canada Funding Company II	Nova Scotia
ConocoPhillips Canada Marketing & Trading ULC	Alberta
ConocoPhillips Canada Pipelines Limited	Alberta
ConocoPhillips Canada Resources Corp.	Nova Scotia
ConocoPhillips Central and Eastern Europe Holdings B.V.	Netherlands
ConocoPhillips China Inc.	Liberia
ConocoPhillips Company	Delaware
ConocoPhillips Continental Holding GmbH	Germany
ConocoPhillips Energy Holding GmbH	Germany
ConocoPhillips European Power Limited	England
ConocoPhillips Funding Ltd.	Bermuda
ConocoPhillips Gas Company	Delaware
ConocoPhillips Germany GmbH	Germany
ConocoPhillips Gulf of Paria B.V.	Netherlands
ConocoPhillips Hamaca B.V.	Netherlands
ConocoPhillips Holdings Limited	England
ConocoPhillips Indonesia Holding Ltd.	British Virgin Islands
ConocoPhillips Indonesia Inc. Ltd.	Bermuda
ConocoPhillips International Holding Ltd.	British Virgin Islands
ConocoPhillips International Inc.	Delaware
ConocoPhillips International Ventures Ltd.	Bahamas
ConocoPhillips JPDA Pty Ltd	Western Australia
ConocoPhillips Libya Waha Ltd.	Cayman Islands
ConocoPhillips Limited	England
ConocoPhillips Mineraloel Grosshandels GmbH	Germany
ConocoPhillips NGL Marketing (Canada) ULC	Alberta
ConocoPhillips Norge	Delaware
ConocoPhillips North Caspian Ltd.	Liberia
ConocoPhillips Oilsands Partnership II	Alberta
ConocoPhillips Petroleum Company U.K. Limited	England
ConocoPhillips Pipe Line Company	Delaware
ConocoPhillips Pipeline Australia Pty Ltd	Western Australia
ConocoPhillips Qatar Funding Ltd.	Cayman Islands
ConocoPhillips Qatar Ltd.	Cayman Islands
ConocoPhillips Russia Inc.	Delaware
ConocoPhillips Sabah Ltd.	Bermuda
ConocoPhillips Skandinavia AS	Norway
ConocoPhillips Surmont Partnership	Alberta

Company Name	**Incorporation Location**
ConocoPhillips Transportation Alaska, Inc.	Delaware
ConocoPhillips WA-248 Pty Ltd	Western Australia
ConocoPhillips West Canada Partnership	Alberta
ConocoPhillips Whitegate Refinery Limited	Ireland
Continental Oil Company (Nederland) B.V.	Netherlands
COP Holdings Limited	England
COPREX LLC	Delaware
Danube Limited	Bermuda
Darwin LNG Pty Ltd	Western Australia
Dubai Marketing Company Limited	Delaware
Dubai Petroleum Company	Delaware
Immingham CHP LLP	England
International Petroleum Holdings LLC	Delaware
Kayo Oil Company	Delaware
Phillips Coal Company	Nevada
Phillips Gas Company Stockholder, Inc.	Delaware
Phillips International Investments, Inc	Delaware
Phillips Investment Company	Nevada
Phillips Oil Company Nigeria Ltd.	Nigeria
Phillips Petroleum International Corporation	Delaware
Phillips Petroleum International Investment Company	Delaware
Phillips-San Juan Partners, L.P.	Delaware
Polar Tankers, Inc.	Delaware
Sooner Insurance Company	Vermont
Springtime Holdings Limited	Cayman Islands
SRW Cogeneration Limited Partnership	Delaware
Sweeny Coker Investor Sub, Inc.	Delaware
The Louisiana Land and Exploration Company	Maryland
Wilhelmshavener Raffineriegesellschaft mbH	Germany

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our reports dated February 25, 2010, with respect to the consolidated financial statements, condensed consolidating financial information, and financial statement schedule of ConocoPhillips, and the effectiveness of internal control over financial reporting of ConocoPhillips, included in this Annual Report (Form 10-K) for the year ended December 31, 2009, in the following registration statements and related prospectuses.

ConocoPhillips Form S-3	File No. 333-157547
ConocoPhillips Form S-4	File No. 333-130967
ConocoPhillips Form S-8	File No. 333-98681
ConocoPhillips Form S-8	File No. 333-116216
ConocoPhillips Form S-8	File No. 333-133101
ConocoPhillips Form S-8	File No. 333-159318

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2010

CERTIFICATION

I, James J. Mulva, certify that:

1. I have reviewed this annual report on Form 10-K of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2010

/s/ James J. Mulva

James J. Mulva
Chairman and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Sigmund L. Cornelius, certify that:

1. I have reviewed this annual report on Form 10-K of ConocoPhillips;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2010

/s/ Sigmund L. Cornelius

Sigmund L. Cornelius
Senior Vice President, Finance, and
Chief Financial Officer

CERTIFICATIONS PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Annual Report of ConocoPhillips (the company) on Form 10-K for the period ended December 31, 2009, as filed with the U.S. Securities and Exchange Commission on the date hereof (the Report), each of the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to their knowledge:

(1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the company.

Date: February 25, 2010

/s/ James J. Mulva

James J. Mulva
Chairman and Chief Executive Officer

/s/ Sigmund L. Cornelius

Sigmund L. Cornelius
Senior Vice President, Finance, and
Chief Financial Officer